CANADIAN
ENERGY
RESEARCH
INSTITUTE

3512 - 33 ST. N.W., Calgary, Alberta — T2L 2A6

Phone: (403) 282-1231

WORKING PAPER 85-2

A PARTIAL REGIONAL COMPARISON OF TAXES AND SUBSIDIES ON NATURAL GAS, ELECTRICITY, AND OIL PRODUCTS IN CANADA

L. Coad
K. Desbarats

MAY 1985

Working papers are distributed by the Canadian Energy Research Institute in limited numbers. They represent the results of work in progress and are made available in this preliminary form both for information and to obtain comments.

The Canadian Energy Research Institute is a co-operative research organization sponsored by six parties: Energy, Mines and Resources Canada, the Alberta Department of Energy and Natural Resources, the Private Energy Research Association (composed of corporate and individual members from oil, gas, coal, electrical, nuclear energy and pipeline companies), The University of Calgary, the Ontario Ministry of Energy, and the Saskatchewan Department of Energy and Mines. The objectives of the Institute are to develop an economic research capability and to conduct studies that will assist industry and government in dealing with energy problems. The research program of the Institute is developed by a Board of Directors named by the sponsoring organizations. The content of the individual studies is, however, the responsibility of the authors.

In addition to undertaking studies in energy economics funded collectively by Institute sponsors, CERI carries out research for clients on a contractual basis.

CONTENTS

FIGURES iii

TABLES iii

ACKNOWLEDGEMENTS v

PREFACE vii

EXECUTIVE SUMMARY ix

CHAPTER 1 INTRODUCTION 1

1.1 Overview 1

1.2 Purposes 1

1.3 Methodology and Scope 2

1.4 Interpreting the Results 3

1.5 Study Organization 4

CHAPTER 2 COMPARISONS OF SELECTED PRICES AND TAXES 7

2.1 The Residential Sector 10

2.2 The Commercial Sector 10

2.3 The Industrial Sector 15

2.4 Summary 15

CHAPTER 3 NATURAL GAS 19

3.1 From the Wellhead to the Toronto City Gate Price 19

3.2 Wholesale Pricing in Alberta and British Columbia 22

3.2.1 Alberta 22

3.2.2 British Columbia 23

3.3 Burner-Tip Prices 26

3.4 Other Issues 30

CHAPTER 4 FUEL OIL 33

4.1 From the Wellhead to the Refinery Gate 33

4.1.1 Pricing Regime 33
4.1.2 Methodological Issues 37
4.1.3 Average Refinery Gate Crude Prices 38

4.2 Through the Refinery 40

4.3 Burner-Tip Prices 42

4.4 Other Issues 46

CHAPTER 5 ELECTRICITY 49

5.1 Background 49

5.2 General Issues 54

5.3 Methodological Issues 55

5.4 End-Use Prices 57

5.5 Other Issues 60

APPENDIX A: DATA SOURCES 67

APPENDIX B: CONVERSION EFFICIENCIES 71

BIBLIOGRAPHY 75

FIGURES

2.1 Secondary Energy Demand in Canada 8

2.2 Secondary Fuel Demand in Canada 9

2.3 Residential Energy Prices and Selected Tax Components, 1984 11

2.4 Commercial Energy Prices and Selected Tax Components, 1984 13

2.5 Industrial Energy Prices and Selected Tax Components, 1984 16

4.1 The Petroleum Compensation Account 35

TABLES

2.1 Residential Energy Tax Components 12

2.2 Commercial Energy Tax Components 14

2.3 Industrial Energy Tax Components 17

3.1 Eastern Wholesale Price of Natural Gas and Its Tax Components 21

3.2 Alberta Wholesale Price and Its Tax Components 24

3.3 B.C. Wholesale Price of Natural Gas and Its Tax Components 25

3.4 Selected Taxes and Burner-Tip Prices of Natural Gas Residential Sector 27

3.5 Selected Taxes and Burner-Tip Prices of Natural Gas Commercial Sector 28

3.6 Selected Taxes and Burner-Tip Prices of Natural Gas Industrial Sector 29

4.1 Domestic and Imported Crude Oil Refined in Canada January-June 1984 36

4.2 Montreal Refinery Acquisition Cost of Crude, June 1984 39

4.3 Regional Refinery Realizations 43

4.4	Crude Cost Component of Fuel Oil	41
4.5	Selected Taxes and Burner-Tip Prices of Light Fuel Oil	44
4.6	Selected Taxes and Burner-Tip Prices of Heavy Fuel Oil	45
5.1	Generating Capacity and Sources of Primary Energy	50
5.2	Sources of Primary Energy	51
5.3	Electricity Sales and Revenues by End Use Sector	53
5.4	Electricity Burner-Tip Price and Tax Component	58
5.5	Selected Taxes and Burner-Tip Prices Residential Sector	59
5.6	Selected Taxes and Burner-Tip Prices Industrial Sector	60
5.7	Selected Taxes and Burner-Tip Prices Commercial Sector	61
B.1	Conversion Efficiency Assumptions	73

ACKNOWLEDGEMENTS

The authors wish to express their gratitude to the members of the advisory committee who provided guidance in delineating the scope of this paper as well as numerous comments on an earlier draft. Any remaining errors or omissions are, of course, the responsibility of the authors. We wish also to express our gratitude to the many individuals and organizations that provided data, as well as guidance in interpreting the data. Particular mention is made of Petro-Canada, TransAlta Utilities and various departments of Energy, Mines and Resources Canada. Finally, we are grateful to CERI staff members Walter Haessel and Charles Slagorsky for their guidance and comments, and S. Ingstrup, M. McCarthy and J. Morrison for typing and preparing drafts of this paper.

EXECUTIVE SUMMARY

This working paper presents some comparisons of taxation of purchased natural gas, electricity, and heating oil (light fuel oil in residential use, heavy fuel oil elsewhere). The taxes are presented net of subsidies, and are compared to end-use prices for the residential, commercial, and industrial sectors based on data for the first half of 1984. The following points are raised:

- Competing fuel prices are more competitive in the major consuming provinces of Ontario and Quebec than in the producing provinces of Alberta and B.C.

- Prices and taxation levels for natural gas are lowest in Alberta and British Columbia, each of which has its own pricing regime for sales within the province.

- Taxation of electricity is lowest in Ontario where about 3.5 percent of the burner-tip price is tax, and highest in British Columbia (19.6 percent to 24.4 percent tax). Levels of taxation on electricity vary substantially between provinces.

- In all regions except Alberta, provincial taxes (mostly royalties) on natural gas are larger than federal taxes. The provincial tax ranges from $14.94 per cubic metre in industrial Alberta to $46.46 in industrial B.C., with most provinces and sectors in the $38 to $40 range. Total federal tax ranges from $32.70 in industrial Alberta to $42.34 in residential Ontario with most regions and sectors falling below $35.50. In Alberta, a price support program reduces total provincial taxes substantially.

- Federal and provincial tax components for fuel oil are roughly equivalent, each falling in the range of 15 percent to 17 percent of the posted price for light fuel oil and 12 percent to 18 percent for heavy fuel oil (varying across regions).

- In the first half of 1984, the deficit that accrued in the Petroleum Compensation Account represented a subsidy of $9.73 on every barrel of oil refined in Canada.

- The levels of taxation of natural gas and fuel oil are substantially higher than those pertaining to electricity. This is true in all regions except industrial B.C.

Chapter 1

INTRODUCTION

1.1 Overview

This working paper examines and compares certain taxes and government subsidies levied against natural gas, electricity, and heating oil in selected regions of Canada in the first half of 1984. The taxes are identified and quantified, then compared to the burner-tip prices[1] of the three fuels. Changes introduced under the Western Accord do not apply directly to the period examined and are discussed but not quantified.

The results presented should be assessed with care. In examining the results, particular attention should be paid to the methodology employed and to the list of taxes or subsidies that have been quantified. The remaining sections of this chapter outline the purposes, content, and methodology of this paper. In addition, the chapters of the study dealing with the individual fuels contain sections on methodological issues. It is hoped that this will provide the reader with an adequate basis for interpreting the results, as well as some assessment of the areas in which further study is indicated.

1.2 Purposes

The purpose of this paper is threefold:

- identify specific taxes levied against energy commodities and their relative importance in various regions and end-use sectors in Canada,
- provide information to both consumers and policy makers concerning the iupact of existing taxation regimes on the cost-competitiveness of alternative fuels, and
- provide a preliminary discussion of methodological approaches or difficulties involved in identifying the impact of certain indirect taxes or subsidies.

The first two purposes are relevant to decisions made by both consumers and governments. The consumer combines relative fuel prices

with capital costs, operating costs, and other considerations to determine which fuel to use. Government decisions to tax or not to tax various forms of energy can influence the consumer's fuel choice to the extent that these taxes affect competing fuel prices. Policy makers should, therefore, examine these impacts to ensure that consistent sets of policy goals are pursued.

The Economic Council of Canada recently released a report outlining a potential energy strategy for the nation.[2] They argue that historically, taxation of oil and natural gas has served a different set of policy goals than has taxation of electricity. The results presented here examine, in part, the implications of those different policies on energy consumers.

1.3 Methodology and Scope

The calculations presented in this paper are based on publicly available aggregate data from a wide variety of government and industry sources.[3] Given the preliminary nature of the study, only direct taxes or subsidies for which data are available are quantified. Other issues are dealt with qualitatively. In the case of taxes levied, the calculations cover all major categories. Where tax exemptions are concerned, it is often difficult to determine how much tax might be paid if the exemption were removed. This study does not examine in detail the entire Canadian tax structure to compare effective rates of taxation for the industries involved, nor does it comment on or quantify taxes that "should" be paid.

Certain direct subsidies, for which data are available, can be easily quantified. An example of this would be income tax rebates. There are also a number of subsidies that are less direct and result from such actions as loan guarantees or expenditures on research and development. These subsidies are far more difficult to quantify.

Another difficult question is how to allocate items such as exploration grants (an easily quantified direct subsidy) across production of energy. Many of these issues require methodological simplifications in order to make quantification possible. Others are discussed only in qualitative terms because an appropriate methodology could not be established or was considered beyond the scope of the study.

This paper relates to the situation in four cities in different regions of Canada (Vancouver, Calgary, Toronto, and Montreal), three

end-use sectors (residential, commercial, and industrial), and three fuels (natural gas, fuel oil and electricity). Throughout the text, any reference to a province applies specifically to the relevant city. As outlined above, all data were collected from publicly available sources and all analyses were based on aggregate data. The time period examined is the first half of 1984 with all prices and taxes reported as of the end of that period. This requires, in some cases, that analysis be based on projected figures, rather than actual values. Coal is not directly examined because of its limited use as a heating fuel. Two-thirds of all coal burned in Canada is used by the electric utility industry to generate power.

The results presented in Chapter 2 are measured in terms of dollars per unit of useful energy.[4] This highlights the interpretation of results in terms of their importance to the relative cost effectiveness of competing fuels.

1.4 Interpreting the Results

Given the partial nature of this analysis, extreme care is required in interpreting the results presented. In order to properly interpret the summary results presented in Chapter 2, the reader should refer to the detailed calculations and methodological discussions presented in subsequent chapters and note the following caveats apply:

- The aggregate measures used may represent average prices or average taxation levels, but cannot be applied directly to any individual or firm. This is particularly important when examining costs across fuels.

- The focus on fuel costs represents only a partial analysis of the fuel choice decision. Other factors such as capital costs, operating costs, availability, safety, convenience, or quality must be included to complete the analysis. Moreover, the analysis focuses on only the conventional energy sources. Alternative energy sources and fuels have not been included.

- Not all taxes or subsidies related to the fuels examined have been quantified. Including additional items (if they could be properly quantified) may substantially affect the results of the analysis.

- Incomplete or unavailable data have made some simplifying assumptions necessary. To the extent that better, more complete data could be collected, the results could be strengthened.

1.5 Study Organization

Chapter 2 presents a summary of the results and comparisons of taxation between fuels and across regions. All figures presented in Chapter 2 are based on results from Chapters 3 to 5 which deal with natural gas, fuel oil, and electricity, respectively. The prices and taxes reported in Chapter 2 are measured in dollars per gigajoule of useful energy. All other chapters use input energy measures. Conversion efficiencies used in Chapter 2 are found in Appendix B.

Footnotes

[1]Burner-tip price refers to the price paid by the final consumer of energy.

[2]Canada, Economic Council of Canada, Connections (Ottawa, Supply and Services Canada, January 1985).

[3]See Appendix A for a list of data sources used.

[4]Useful energy refers to the energy produced by the fuel burning appliance. This "output" of energy is less than the heat content of the fuel entering the appliance, due to a variety of technical factors. The ratio of output energy to input energy is referred to as conversion efficiency. For a technical description of various measures of efficiency, see Berndt (1978).

Chapter 2

COMPARISONS OF SELECTED PRICES AND TAXES

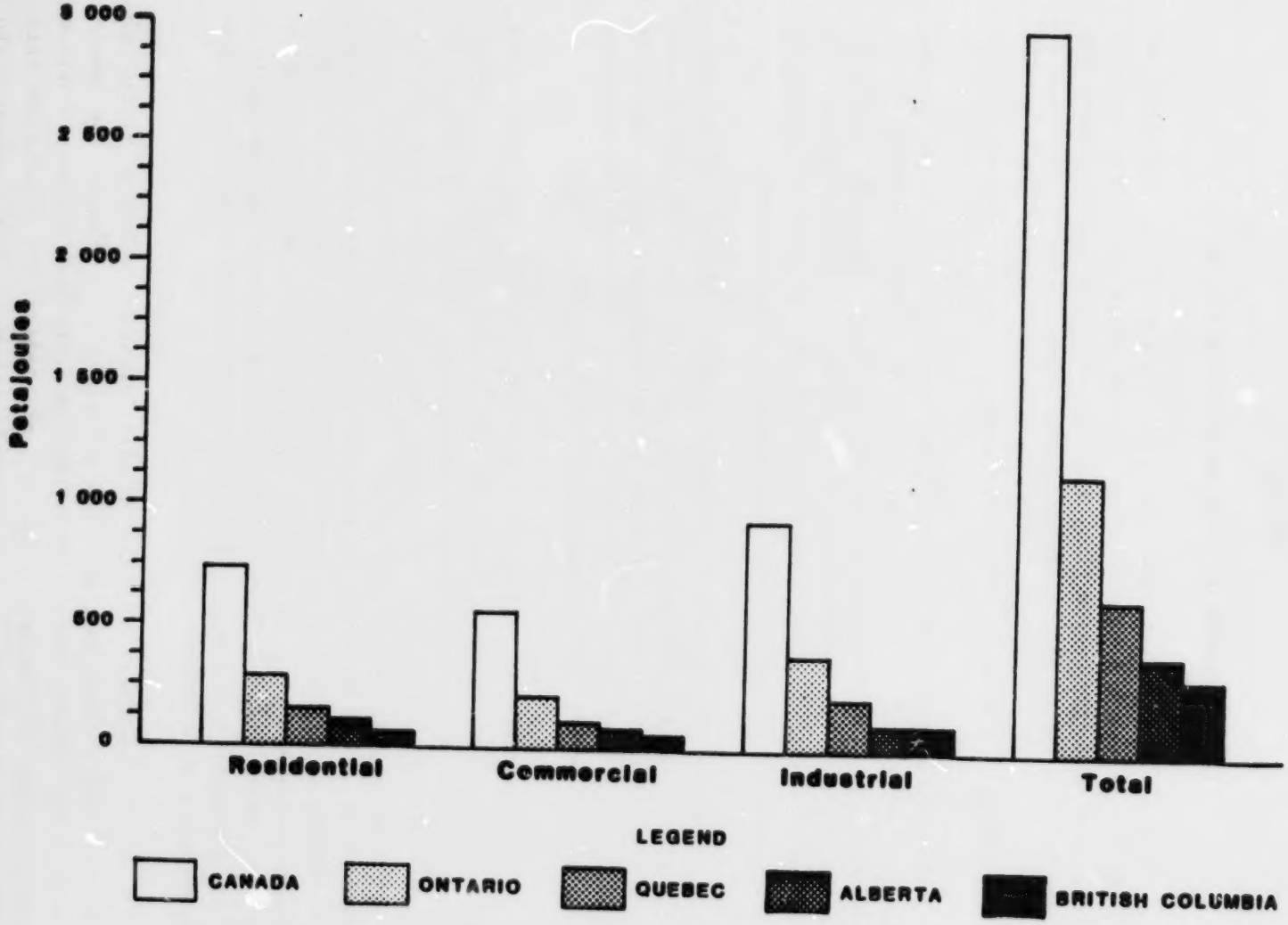
This chapter outlines the main results of our analysis of burner-tip prices and related taxes net of subsidies. Some general background on energy consumption in Canada will help explain the choice of regions and place the results in perspective.

Figure 2.1 shows secondary energy demand for Canada and the four regions examined. In all three sectors examined, Ontario, by virtue of its population and industrial base, is by far the largest consumer of energy. Of the total residential and commercial energy consumption, Ontario accounts for 38 percent. For the industrial sector, Ontario consumes 41 percent of the total. Taken together, the regions examined account for 82 percent of residential/commercial energy consumption and 87 percent of industrial consumption.

Figure 2.2 presents secondary energy consumption by fuel. Natural gas and electricity are by far the most important energy commodities, accounting for 53 percent of all secondary energy demand in Canada. Fuel oil accounts for an additional 10 percent of secondary demand, with other fuels accounting for the remaining 37 percent.

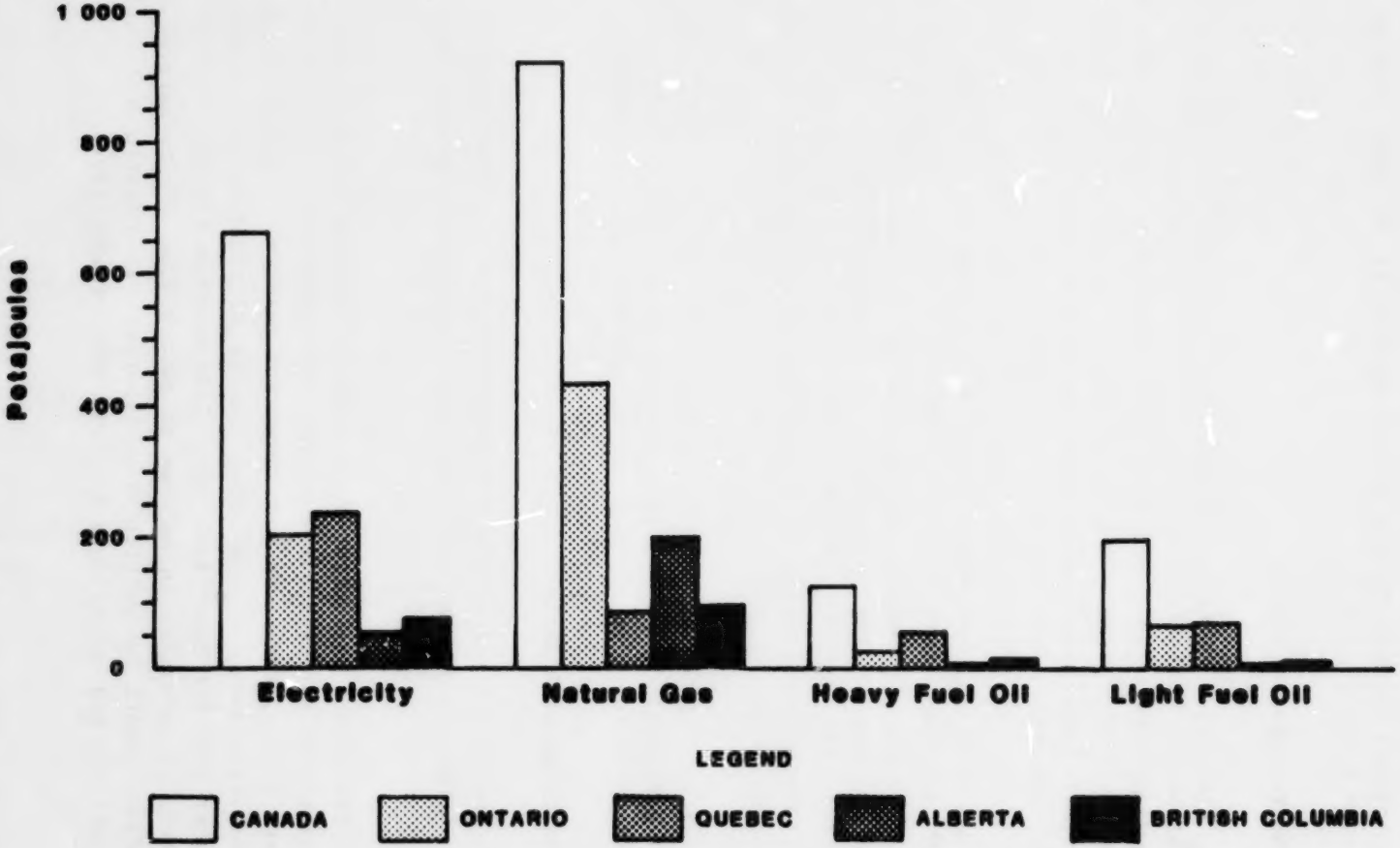
Comparison of Figures 2.1 and 2.2 reveals some interesting facts. Quebec, which accounts for 21 percent of secondary energy demand, contributes 36 percent of electricity demand, 43 percent of heavy fuel oil demand, and 35 percent of light fuel oil demand, yet only 9 percent of natural gas demand. Alberta, which accounts for 13 percent of secondary energy demand, accounts for 22 percent of natural gas demand, 8 percent of electricity demand, and almost no fuel oil. These region-specific consumption patterns reflect a host of influences. Among these influences are burner-tip prices, market penetration (consumer acceptance), availability or proximity of supply, and transportation systems.

The remainder of this chapter examines relative prices of electricity, natural gas, and fuel oil along with selected tax components. The summary results presented are drawn from the more detailed presentations of Chapters 3 to 5. All tables and figures in this chapter are presented in units of useful energy. This represents the



SOURCE: Statistics Canada, Quarterly Report on Energy Supply-Demand in Canada, 57-003, 1984-II.

FIGURE 2.1: SECONDARY ENERGY DEMAND IN CANADA (JAN. - JUNE 1984)



SOURCE: Statistics Canada, Quarterly Report on Energy Supply-Demand in Canada, 57-003, 1984-II.

FIGURE 2.2: SECONDARY FUEL DEMAND IN CANADA (JAN. - JUNE 1984)

energy available after accounting for losses in combustion which arise because the furnaces, boilers, etc. which burn fuel oil or natural gas do not transform 100 percent of the heat available in the fuel into heat available to do work. A simple example is the heat loss up the chimney of a furnace.

2.1 The Residential Sector

Figure 2.3 shows retail prices and tax components for all fuels and regions for residential consumers. Table 2.1 divides the tax into its federal, provincial, and municipal components, showing each as a percentage of the price. Figure 2.3 shows that in Ontario and Quebec residential fuel prices are more competitive than in Alberta and British Columbia. The low price of natural gas in Alberta is the result of two factors. First, Alberta is a large producer of natural gas which means that transportation costs from the wellhead to the consumer are lower than in other regions. Second, and more important in terms of relative magnitude, the Alberta government has established a price support program (see Chapter 3 for details). The higher tax percentages for natural gas in Alberta reflect the low burner-tip price; taxes in dollars per gigajoule are noticeably lower in Alberta than in any other region.

From Figure 2.3 and Table 2.1 it is evident that taxes on natural gas and fuel oil are roughly comparable. Taxes on electricity are noticeably lower in all regions and are the lowest in Ontario.

2.2 The Commercial Sector

Burner-tip prices and tax components for the commercial sector are presented in Figure 2.4, with tax components reported in Table 2.2.

The commercial sector shows overall lower prices and a narrower range of prices across fuels than does the residential sector. Due to the lower prices, taxes are more important relative to energy prices in the commercial sector. The actual levels of taxation on natural gas are higher than for heavy fuel oil. This is true for all regions, and could tend to undermine incentives to switch from oil to natural gas. This effect would be particularly important in Ontario and Quebec, where fuel oil and natural gas are very price-competitive.

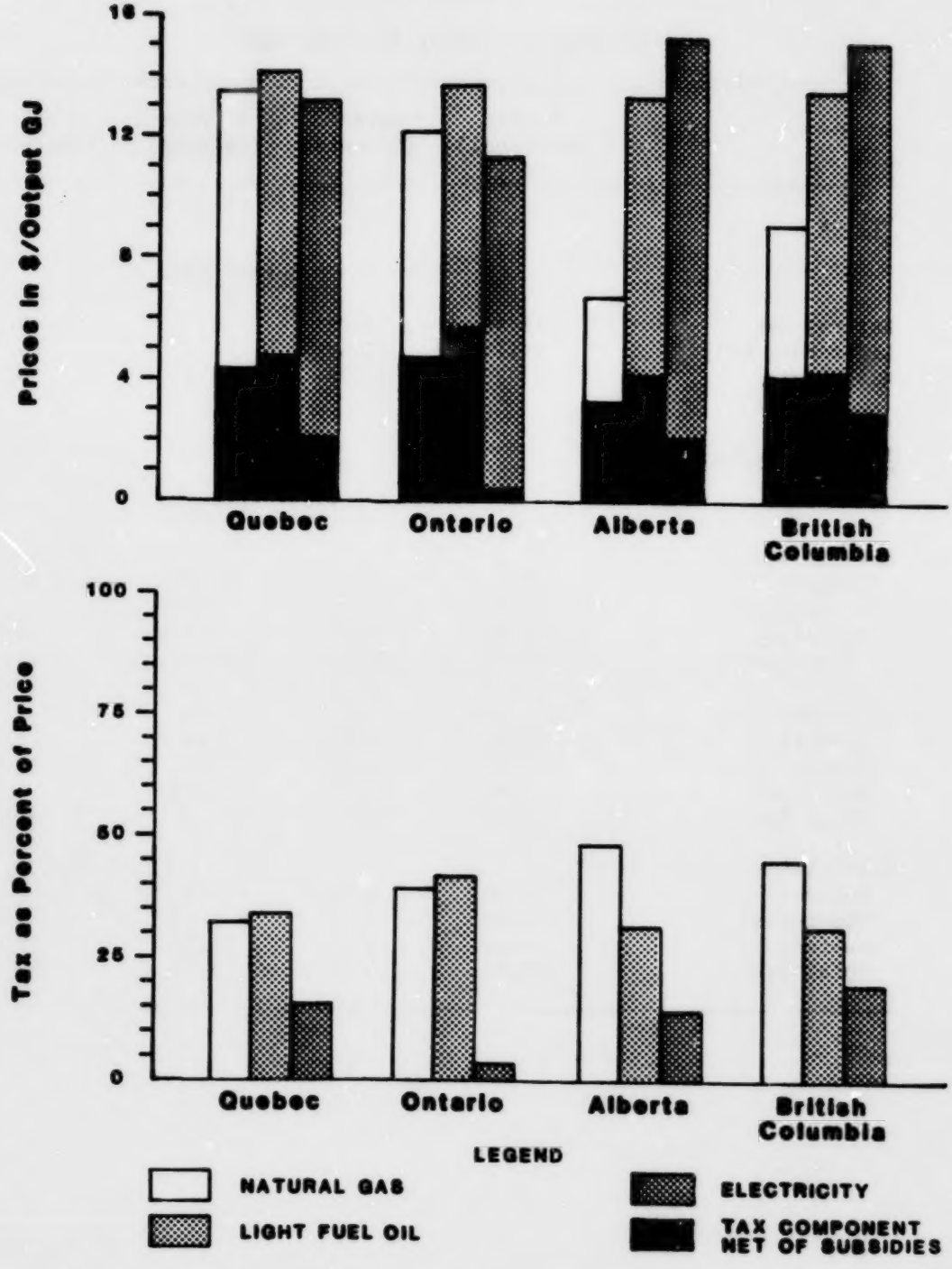


FIGURE 2.3: RESIDENTIAL ENERGY PRICES AND SELECTED TAX COMPONENTS, 1984

TABLE 2.1

RESIDENTIAL ENERGY TAX COMPONENTS

	Quebec (Montreal)	Ontario (Toronto)	Alberta (Calgary)	B.C. (Vancouver)
Prices				
		$/Output GJ		
Natural Gas	13.46	12.19	6.71	9.10
Light Fuel Oil	14.12	13.69	13.37	13.57
Electricity	13.20	11.36	15.28	15.15
Tax Components				
		Percent of Price		
Natural Gas				
Federal	13.90	18.50	25.90	20.10
Provincial	16.30	17.30	12.50	22.20
Municipal	2.00	3.00	9.80	3.00
Total Tax	32.20	38.80	48.30	45.30
Light Fuel Oil				
Federal	14.80	14.80	14.80	14.90
Provincial	17.60	15.00	15.60	15.40
Municipal	1.40	11.70	0.90	1.00
Total Tax	33.80	41.50	31.30	31.30
Electricity				
Federal	0.00	0.00	0.40	0.00
Provincial	13.70	1.70	2.20	8.60
Municipal	1.90	1.70	11.30	11.00
Total Tax	15.60	3.40	13.90	19.60

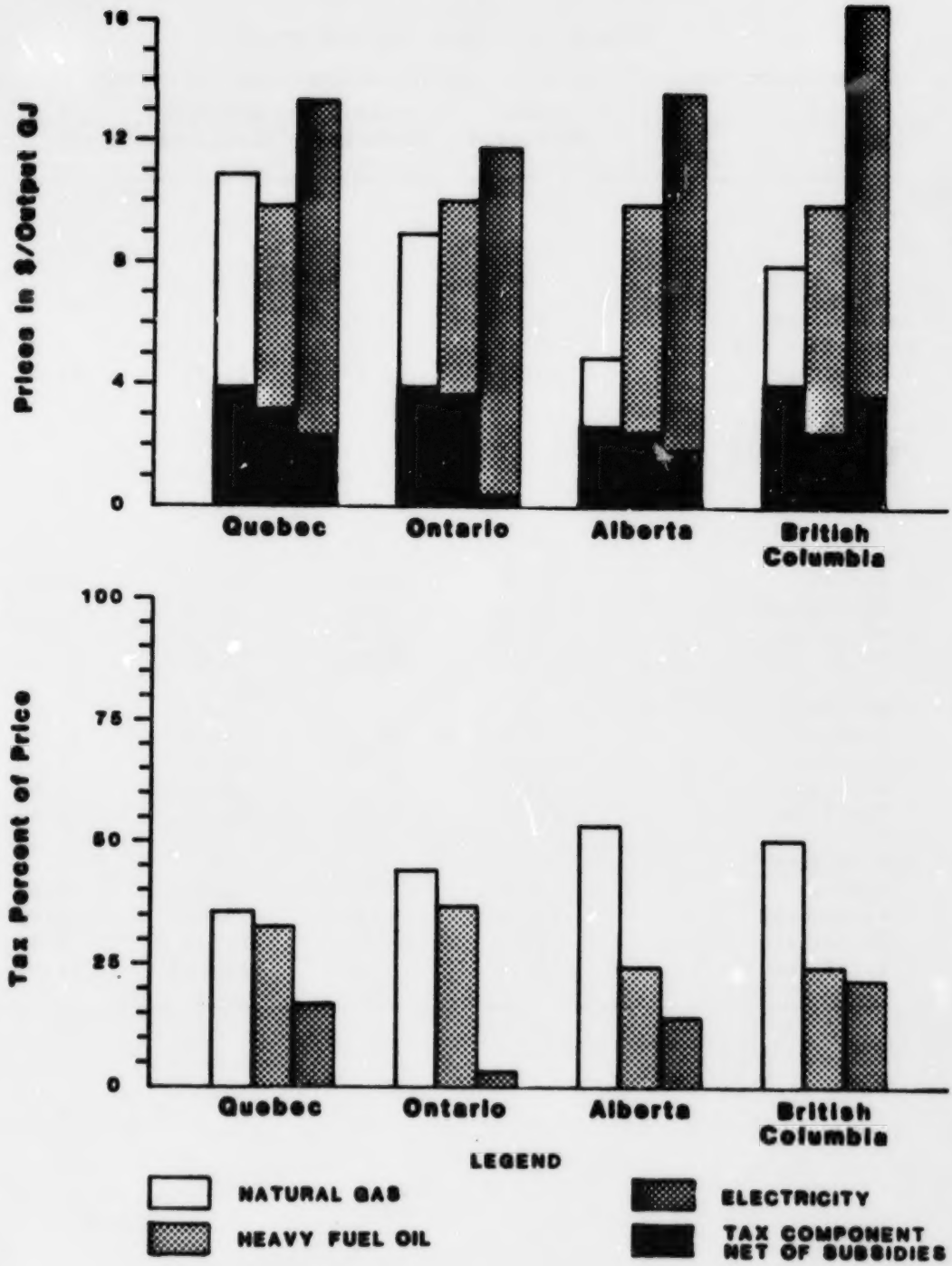


FIGURE 2.4: COMMERCIAL ENERGY PRICES AND SELECTED TAX COMPONENTS, 1984

TABLE 2.2

COMMERCIAL ENERGY TAX COMPONENTS

	Quebec (Montreal)	Ontario (Toronto)	Alberta (Calgary)	B.C. (Vancouver)
Prices				
		$/Output GJ		
Natural Gas	10.85	8.97	4.91	7.96
Light Fuel Oil	9.84	10.00	9.91	9.95
Electricity	13.31	11.75	13.59	16.59
Tax Components				
		Percent of Price		
Natural Gas				
Federal	15.30	19.80	28.90	20.50
Provincial	18.10	20.60	14.70	27.00
Municipal	2.20	3.60	10.00	2.90
Total Tax	35.60	44.00	53.60	50.40
Light Fuel Oil				
Federal	13.30	11.70	11.60	11.60
Provincial	17.80	12.10	12.10	12.00
Municipal	1.50	12.70	0.90	0.90
Total Tax	32.60	36.50	24.60	24.40
Electricity				
Federal	0.00	0.00	0.40	0.00
Provincial	15.30	1.70	2.40	14.00
Municipal	2.00	1.90	11.30	7.90
Total Tax	17.30	3.60	14.10	21.90

2.3 The Industrial Sector

Industrial energy prices and tax components are presented in Figure 2.5 and Table 2.3. Industrial energy prices are the lowest of the three sectors, reflecting the lower cost of serving industrial customers, as well as any cross-subsidization that may occur. Industrial electricity prices show a narrower range across regions and are again lowest in Quebec and Ontario. The electricity price in Quebec is lower than both fuel oil and natural gas, reflecting the Quebec government's policy to encourage electricity consumption.

It is also interesting that taxation levels in dollars per output gigajoule and as a percentage of the burner-tip price are noticeably larger for natural gas than for fuel oil. This appears to contradict the objective of off-oil conversion programs.

A final note with respect to the industrial sector concerns fuel oil and electricity prices in British Columbia. Although levels of prices and taxes are different, taxes as a percent of price are comparable. This reflects the higher level of provincial and municipal taxes on electricity (water rentals in particular).

2.4 Summary

The above comparisons reveal several trends. Prices of natural gas are lowest in Alberta and B.C., the two major gas producing provinces. The level of net taxation of natural gas is lowest in Alberta. This reflects government measures to protect consumers from high natural gas prices.

In the residential and commercial sectors, the level of taxation on electricity is highest in British Columbia and Quebec. In the industrial sector, electricity taxation is highest in British Columbia. This probably reflects the high percentage of electricity generated in those provinces by hydroelectric stations and the imposition of water rentals on the use of hydroelectric sites. The low level of taxation in industrial Quebec reflects a desire to encourage electricity consumption rather than natural gas or fuel oil.

It is also evident that levels of taxation of natural gas and fuel oil are substantially higher than those for electricity. This is true in all regions (except industrial B.C.) and reflects a variety of factors. In part, the difference represents the potential of natural

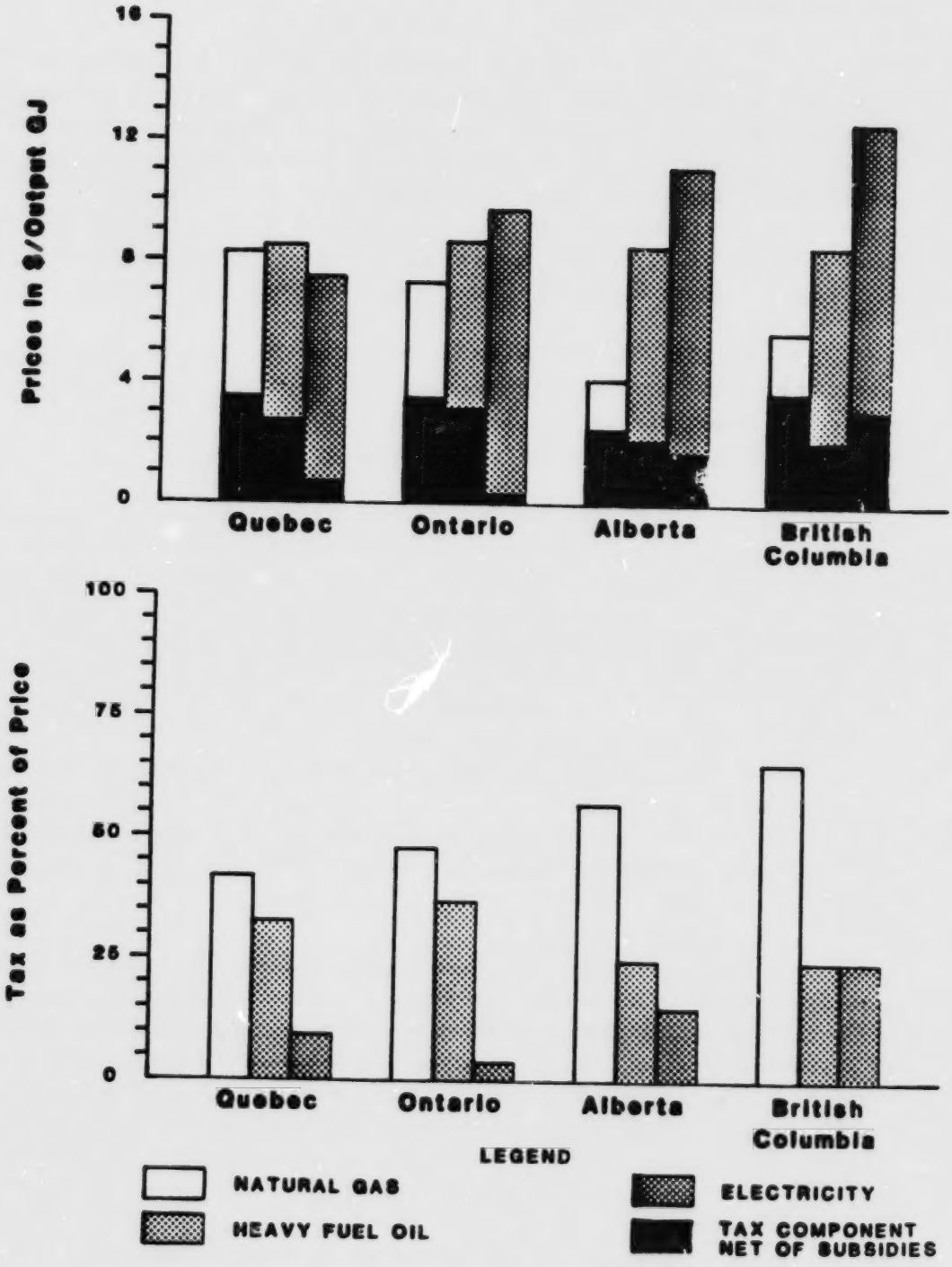


FIGURE 2.5: INDUSTRIAL ENERGY PRICES AND SELECTED TAX COMPONENTS, 1984

TABLE 2.3

INDUSTRIAL ENERGY TAX COMPONENTS

	Quebec (Montreal)	Ontario (Toronto)	Alberta (Calgary)	B.C. (Vancouver)
Prices				
		$/Output GJ		
Natural Gas	8.26	7.26	4.11	5.67
Light Fuel Oil	8.48	8.62	8.54	8.57
Electricity	7.45	9.73	11.14	12.62
Tax Components				
		Percent of Price		
Natural Gas				
Federal	18.30	21.50	30.90	26.60
Provincial	21.50	22.60	16.10	36.00
Municipal	2.70	3.60	9.70	2.80
Total Tax	42.50	47.80	56.70	65.40
Light Fuel Oil				
Federal	13.30	11.70	11.60	11.60
Provincial	17.80	12.20	12.10	11.90
Municipal	1.50	12.60	0.90	0.90
Total Tax	32.60	36.50	24.60	24.40
Electricity				
Federal	0.00	0.00	0.50	0.00
Provincial	7.10	2.00	3.00	16.50
Municipal	2.30	1.70	11.30	7.90
Total Tax	9.40	3.70	14.80	24.40

gas and oil to generate economic rents on international markets. In part it represents the difference in control of resources: federal-provincial pricing agreements are required for oil and gas, whereas electricity is priced within each province by a provincial authority.

The above comparisons, together with the following chapters, attempt to point out relative levels of taxation between competing fuels in Canada. It is hoped that such a presentation can contribute to the discussion of energy policy goals and their accomplishment.

Chapter 3

NATURAL GAS

3.1 From the Wellhead to the Toronto City Gate Price

Under the current system, natural gas prices in Canada are the outcome of a complex series of regulatory decisions which affect each stage of the marketing of gas. As a result, the analysis of this chapter draws on a broad range of sources. The upstream taxation scheme is based on aggregate data from the Petroleum Monitoring Agency and receives a more complete discussion in the next chapter.[1] Rate applications filed by gas transportation and distribution companies are the major source of data for the remaining price and tax calculations. Before developing the results, a brief discussion of the pricing and fiscal regime which prevailed in the first half of 1984 is presented.

Under the 1981 Federal/Alberta Memorandum of Agreement, the Alberta Border Price (ABP) was established as the reference for Eastern Canadian natural gas pricing. The APB is the price of gas sold in Canadian markets east of the Alberta border, as it enters the TransCanada Pipeline system. The ABP incorporates a regulated field price, an "export flowback," and the Alberta cost of service. The latter is a regulated charge to producers for the gathering and transportation of gas from the wellhead to the border on facilities owned by Nova, An Alberta Corporation. The tax component of the ABP includes federal and provincial income taxes, Crown royalties, property taxes and the Petroleum and Natural Gas Revenue Tax (PGRT) paid out of the wellhead price by producers. It also includes the income and property tax component of Nova's cost-of-service charge.

Wholesale natural gas prices in Canada hinge on the federal government's policy of maintaining the Toronto City Gate Price at 65 percent of the equivalent refinery cost of oil. Regulated transportation tariffs and federal taxes make up the difference between the ABP and the Toronto City Gate Price. The transportation charges incorporate income and property taxes paid by TransCanada Pipelines Limited (TCPL), as well as federal and provincial excise taxes imposed on the

purchase of gas consumed during the course of TCPL's transmission operations.

To comply with the ceiling imposed on natural gas prices, the federal government has varied the excise tax on pipeline marketable gas: the Natural Gas and Gas Liquids Tax (NGGLT) was reduced to zero on February 1, 1984. The Canadian Ownership Special Charge, in turn, can be varied to absorb transportation cost increases in excess of 5 percent. Thus, as far as producers are concerned, gas wellhead prices and gas netbacks are not directly linked to oil prices, but rather to the ABP as set by the Alberta government. However, consumer prices, federal government revenues and the rate of return on pipeline transportation are affected by the 65 percent parity rule.

Producers' incomes are also affected by a dual pricing system. The export prices set by the federal government are higher than the Alberta Border Price. The difference between the two is paid into an Export Price Adjustment Fund which is partly redistributed to Alberta producers in proportion to their total production volumes in the form of an "export flowback." Thus, under this system, producers receive the same price for all volumes sold, whether to export or domestic markets, and regardless of whether they actually export any gas. Within Canada, the export flowback system amounts to a transfer from producers selling on the U.S. market to producers of gas sold domestically and should not, therefore, be considered a subsidy. The remainder of the fund contributes to a scheme of Market Development Incentive Payments, which is designed to encourage the growth of eastern markets for Alberta gas.[2] The Alberta Petroleum Marketing Commission transfers the funds to the federal government which then subsidizes the costs incurred by various gas utilities for the expansion of their distribution systems. The dual pricing system thus transfers income from foreign consumers to domestic producers, and, ultimately, to certain domestic consumers, to the extent that the grants serve to dampen price increases for the recipient utilities.

The eastern wholesale price of natural gas and its tax components are shown in Table 3.1. The figure represents the average toll charged by TCPL to gas utilities operating in its eastern zone (which embraces the Toronto and Montreal markets) plus the Canadian Ownership Special Charge (COSC) levied on domestic natural gas received for processing or consumption and imposed on the processor or consumer, as the case may be. The TCPL toll charge is reviewed by the National Energy Board, usually on an annual basis. It reflects the transport cost of

TABLE 3.1

EASTERN WHOLESALE PRICE OF NATURAL GAS AND ITS TAX COMPONENTS[a]

	$/10^3m^3$	% of Wholesale Price
Eastern Wholesale Price	145.13	
TCPL Toll (including cost of gas)	139.83	
Royalty Component[b]		
Average Provincial	30.33	
Average Federal	0.05	
Total Royalty	30.38	
Upstream Income and Property Tax		
Provincial Income Tax	3.98	
Federal Income Tax	14.56	
Total Income Tax	18.54	
Non Income Tax	0.47	
Gathering and Transmission[c]		
Provincial Income Tax	0.67	
Federal Income Tax	1.93	
Total Income Tax	2.60	
Non Income Tax[d]	5.67	
Provincial	1.26	
Municipal	4.41	
Total	8.27	
Other Federal Taxes		
PGRT[e]	10.48	
COSC[f]	5.73	
Total Taxes		
Municipal	4.88	3.36
Provincial	36.24	24.97
Federal	32.75	22.56
Total	73.87	50.89

SOURCES: (1) Energy Pricing News, various issues; (2) Petroleum Monitoring Agency, Petroleum Monitoring Survey, 1984, First Six Months; (3) TCPL 1984 rate application; and (4) Nova, An Alberta Corporation, Annual Report 1983.

[a]Figures do not include subsidies arising from the Distribution System Expansion Program.

[b]For a discussion underlying the royalty, PGRT and upstream income tax calculation, see the following chapter, section 4.1.1.

[c]Data unavailable on non-income tax component of the Nova charge.

[d]This non-income tax figure includes provincial sales tax and municipal and provincial property taxes imposed on TCPL.

[e]The PGRT will be gradually eliminated over the period of January 1, 1986-December 31, 1988.

[f]The COSC differs from the official $5.30 per thousand cubic metres by an amount which reflects the excise tax paid out by TCPL for gas consumed during its transmission operation which is then allocated out on the basis of the utility's sales. The COSC was eliminated in the federal-provincial pricing agreement of March 28, 1985.

carrying gas from the Alberta boundary to Eastern Canada. These costs are allocated to TCPL's customers on the basis of volumes carried and distance travelled. It should be noted, however, that cross-subsidization within geographical regions occurs, since the TCPL charge does not reflect transport cost differences within a toll zone. For example, both Toronto and Montreal are in TCPL's eastern zone. The toll charged in that zone represents the average cost of service, although that cost is higher for Montreal than for Toronto.

The eastern wholesale price, then, is the sum of the ABP, set at $105.67 per thousand cubic metres in February 1984 (or $2.79/GJ), and the TCPL tolls and the COSC, less any subsidies arising from the Market Incentive Development payments, which are not quantified in this paper. Prior to February 1, 1984, the eastern wholesale price also included the NGGLT. Taxes represent roughly one-half of the wholesale cost of gas in Toronto and Montreal and most are collected on the well-head price, before the transmission stage.

3.2 Wholesale Pricing in Alberta and British Columbia

The pricing provisions contained in the National Energy Program extended only to gas sold east of Alberta. Gas sold within the producing provinces falls under the jurisdiction of the provincial governments which have developed distinct pricing regimes. The following sections outline the different wholesale pricing systems in Alberta and British Columbia.

3.2.1 Alberta

The contract prices and volumes of natural gas sold within Alberta are not regulated. Gas purchasers, whether individual utilities, pipeline companies, or large industrial users, may negotiate directly with Alberta producers to establish the terms of their purchase contracts. A provincial price support program, however, imposes a ceiling on the wholesale price of gas. Under the Natural Gas Rebates Act, certain gas customers are refunded the difference between their purchase price and the support price currently set at 65 percent of the ABP. As of February 1984, the support price amounted to $68.63 per thousand cubic metres, compared with the ABP of $105.67 per thousand cubic metres. The actual subsidy to gas purchasers benefiting from the support scheme will vary with the purchase price, which in some cases may fall below the support price.

Table 3.2 identifies the tax components of the wholesale price of gas sold to one of the two major gas distributors in Alberta. Ninety-five percent of Canadian Western Natural Gas' supply requirements are met through sales which are eligible for a rebate, while 3.5 percent are met through its own production which is assigned a "deemed value" equal to the ABP net of the Alberta cost of service ($12.50 per thousand cubic metres). The subsidy on sales can then be computed as the difference between this "deemed value" and the Alberta Support Price. Thus, after February 1984, the subsidy on sales eligible for a rebate amounted to $24.54 per thousand cubic metres. The figures suggest that the Alberta government's share of the revenue generated from "rebateable" intraprovincial sales is well below the federal share. The subsidy scheme also implies that the Alberta government extracts a greater portion of revenue from gas sales outside the province. The total wholesale tax component for Alberta gas is also lower than the eastern wholesale tax component as a result of the taxes included in the TransCanada Pipelines Tariff. The Alberta taxes represent a greater share of the provincial wholesale price, but this is simply because the Alberta wholesale price is considerably lower as a result of lower transportation costs, the absence of price regulation within the province, and the sales rebates.

3.2.2 British Columbia

Natural gas prices in British Columbia are set by the provincial government and most sales are administered by a central marketing agency, the British Columbia Petroleum Commission (BCPC). Producers do not pay an explicit royalty on production from Crown lands. (This amounts to most gas sales, since over 95 percent of the gas rights within the province belong to the Crown.) Instead, the provincial government collects the difference between the costs of the BCPC's gas purchases and the receipts from its only buyer, the Westcoast Transmission Company.[3] The value of this implicit producer royalty is shown in Table 3.3. Other taxes on producers include federal and provincial income taxes and the Petroleum and Natural Gas Revenue Tax.

The wholesale price of natural gas in B.C. also incorporates gathering and transportation charges incurred by the Westcoast Transmission Company. The pipeline tariff is regulated by the National Energy Board, since the transportation company sells gas to export markets. The charge includes income, capital, and property taxes. The tax component of the wholesale price of gas in British Columbia appears to be quite high compared to the other regions under study, but this is

TABLE 3.2

ALBERTA WHOLESALE PRICE AND
ITS TAX COMPONENTS

	$/10^3m^3$	% of Wholesale Price
Alberta Wholesale Price		
Provincial Support Price	68.70	
COSC[a]	5.30	
Royalty Component[b]		
Federal	0.05	
Provincial	30.87	
PGRT[c]	10.48	
Income Tax		
Federal	15.55	
Provincial	4.24	
Non-Income Taxes		
Provincial Mineral Taxes	2.74	
Other	0.47	
Subsidy (Provincial Support Payments)	24.46	
Total Tax	69.03	93.28
Taxes Net of Subsidy		
Municipal	0.47	0.64
Provincial	13.39	18.09
Federal	31.38	42.40
Total	44.57	61.63

SOURCES: (1) Energy Pricing News, various issues; and (2) Petroleum Monitoring Agency, Canadian Petroleum Industry Monitoring Survey, 1984, First Six Months.

[a]Royalty and income tax figures represent provincial averages and so will not give an accurate picture of the taxes facing an individual operator. For further discussion of the calculations underlying income taxes and the federal energy taxes, see the next chapter, section 4.4.1

[b]The COSC was eliminated in the federal-provincial pricing agreement of March 28, 1985.

[c]The PGRT will be gradually eliminated over the period of January 1, 1986 to December 31, 1988.

TABLE 3.3

B.C. WHOLESALE PRICE OF NATURAL GAS
AND ITS TAX COMPONENTS

	$/10^{3}m^3	% of Wholesale Price
B.C. Wholesale Price	96.20	
Royalty Component[a]		
Provincial	25.42	
Federal	0.02	
Federal Charges		
PGRT[b]	10.48	
COSC[c]	5.30	
Income Tax[d]		
Federal	18.51	
Provincial	5.73	
Non-Income Taxes[e]		
Property Tax	5.24	
Other Provincial	1.61	
Municipal	0.47	
Total Tax		
Municipal	0.47	0.49
Provincial	38.00	39.50
Federal	34.31	35.66
Total	72.78	75.65

SOURCES: (1) Energy Pricing News, various issues; (2) WestCoast Transmission Ltd., Annual Report 1983; and (3) Petroleum Monitoring Agency, Canadian Petroleum Industry Monitoring Survey, 1984, First Six Months.

[a]Royalty figures calculated from data supplied by the British Columbia Ministry of Natural Resources. They represent province-wide averages of the "implicit" producer royalties.

[b]The PGRT will be gradually eliminated over the period of January 1, 1986 to December 31, 1988.

[c]The COSC was eliminated in the federal-provincial pricing agreement of March 28, 1985.

[d]Income tax figures represent provincial averages. For further discussion of calculations underlying income taxes and the federal energy taxes, see the next chapter, section 4.1.1. The figure shown for Westcoast Transmission's share of income taxes and property taxes is biased upward because taxes attributable to oil and gas related operations could not be separated from available information.

[e]The split between provincial and municipal property taxes at the transmission stage was not available. Westcoast Transmission's property taxes are all treated as a provincial charge.

at least in part due to the difficulty of apportioning income and property taxes between oil and gas at the transmission stage.

3.3 Burner-Tip Prices

Most of the taxes on natural gas are levied at the upstream stage. Taxes levied on gas distributors include income and property taxes which amount to a relatively small share of the total tax figure and the burner-tip price. In British Columbia, where no income taxes are paid at the distribution end, the tax burden is increased by a 7 percent sales tax on non-residential consumers. This levy raises the provincial share of taxes above the federal tax share of burner-tip prices. Natural gas consumers in Quebec are exempt from the 9 percent sales tax which falls on non-industrial consumers of electricity. Despite this exemption, provincial taxes on all rate groups are relatively high in Quebec, and exceed the federal share of burner-tip prices. Indeed, of the provinces discussed here, only in Alberta does the federal tax cost component systematically exceed the provincial share.

The burner-tip prices shown in Tables 3.4 to 3.6 are average figures drawn from the gas distribution companies' most recent rate applications. They are based on expected sales and revenue figures under the proposed rate structures. As such, they are representative figures which do not distinguish between demand and energy charges and possible seasonal variations in prices. Not surprisingly, burner-tip prices are lower in the producing provinces. Residential and commercial rates tend to be higher than industrial rates in all regions because of high fixed distribution costs which must be spread over relatively small volumes.

The allocation of taxes across the different customer classes poses a number of problems and simplifying assumptions have to be made. Cost-of-service data were not available for the gas distributing companies serving Vancouver and Montreal. As a result, it was not possible to assign to the different rate groups an amount which reflects their responsibility for the tax component of costs. Instead, property and capital taxes have been allocated to the different rate groups on the basis of revenues, as a proxy for allocation according to the rate base. This procedure will be inaccurate when cross-subsidization between customer classes occurs, since revenues will not be a good indicator of where costs are incurred. Given the magnitude of distribution taxes, the errors involved should be of a relatively

TABLE 3.4

SELECTED TAXES AND BURNER-TIP PRICES OF NATURAL GAS
RESIDENTIAL SECTOR
($/10^{3}m^3)

	Montreal	Toronto	Calgary	Vancouver
Burner-Tip Prices[a]	252.84	229.01	126.24	171.05
Wholesale Cost Component				
Municipal Taxes	4.88	4.88	0.47	0.47
Provincial Taxes	36.24	36.24	14.62[b]	38.00
Federal Taxes	32.75	32.75	31.38	34.31
Other Taxes				
Provincial Property and/or Capital Tax	0.95	0.37	-	-
Sales Tax	-	-	-	-
Other Provincial Taxes	3.64	-	-	-
Municipal Property and/or Franchise Tax	0.23	2.17	11.86	4.76
Downstream Income Tax[c]	3.42	12.72	6.21	-
Provincial	0.75	3.13	1.20	-
Federal	2.67	9.59	5.01	-
Total Taxes	82.10	89.13	64.94	77.54
Municipal	5.11	7.05	12.33	5.23
Provincial	41.58	39.74	15.82	38.00
Federal	35.41	42.34	36.39	34.31
		Percent of Burner Tip Prices		
Total Taxes	32.46	32.92	51.12	45.33
Municipal	2.02	3.08	9.77	3.06
Provincial	16.44	17.35	12.53	22.21
Federal	14.00	18.49	28.82	20.06

[a]Ontario's burner-tip prices and tax component are drawn from Consumers' Gas May 1983 rate application to the Ontario Energy Board, E.B.R.O. 395, Exhibit Numbers Q4-Q5. Quebec's burner-tip prices come from Gaz Metropolitain's "Cause Tarifaire," #2943-83. The British Columbia burner-tip prices were computed from data provided by the British Columbia Ministry of Energy, Mines, and Petroleum Resources. The Alberta burner-tip prices are drawn from the Canadian Western Natural Gas (CWNG) rate schedule effective March 1984. They are net of the subsidy provided under the gas rebate scheme. Prices do not include the effect of subsidies arising from the Distribution System Expansion Program.

[b]The effective value of the subsidy to consumers of CWNG is less than $24.46 per thousand cubic metres since only 95 percent of utilities gas requirements are met from sales that are eligible for a rebate. The net provincial tax figure of $14.62/10^{3}m^3 is thus higher than the figure shown in Table 3.2, i.e., $13.39/10^{3}m^3.

[c]The downstream component of British Columbia's property tax has been allocated only over domestic sales revenue for 1984 and will thus overstate the actual tax as a share of domestic consumers' expenditure. Downstream taxes in Alberta are based on projected 1983 numbers drawn from a 1982 CWNG cost-of-service study. Since that time, two rate increases have been approved to meet higher gas costs. No other cost increases have been built into the rates. Increases in other costs will affect the figures for the return to equity rather than customer revenues, so the 1983 tax figures provide a reasonable approximation for the tax component of 1984 rates. The 1984 rates shown moreover incorporate only a fraction of the official unit value of the federal excise tax charged to consumers. Excess revenue generated from the specific excise tax charge in previous years absorbed the difference. The federal tax portion of the wholesale tax component, which is shown here, thus overstates the actual amount paid by CWNG's customers in 1984.

TABLE 3.5

SELECTED TAXES AND BURNER-TIP PRICES OF NATURAL GAS
COMMERCIAL SECTOR
($/10^{3}m^3)

	Montreal	Toronto	Calgary	Vancouver
Burner-Tip Prices[a]	226.99	187.89	102.70	166.52
Wholesale Cost Component				
Municipal Taxes	4.88	4.88	0.47	0.47
Provincial Taxes	36.24	36.24	14.62[b]	38.00
Federal Taxes	32.75	32.75	31.38	34.31
Other Taxes				
Capital Taxes	0.85	0.33	-	
Sales Tax	-	-	-	10.89
Other Provincial Taxes	3.28	-	-	
Municipal Property and/or Franchise Tax	0.21	1.87	9.68	4.33
Downstream Income Tax[c]	3.07	5.92	2.51	-
Provincial	0.68	1.95	0.49	-
Federal	2.39	4.47	2.02	-
Total Taxes	81.28	82.49	58.66	84.31
Municipal	5.09	6.75	10.15	4.80
Provincial	41.05	38.52	15.11	45.20
Federal	35.14	37.22	33.40	34.31
		Percent of Burner-Tip Prices		
Total Taxes	35.81	43.90	57.11	50.62
Municipal	2.24	3.59	9.88	2.88
Provincial	18.08	20.50	14.71	27.14
Federal	15.48	19.81	32.52	20.60

NOTES: See Table 3.4.

TABLE 3.6

SELECTED TAXES AND BURNER-TIP PRICES OF NATURAL GAS
INDUSTRIAL SECTOR
($/10^{3}m^3)

	Montreal	Toronto	Calgary	Vancouver
Burner-Tip Prices[a]	188.43	165.56	93.74	129.40
Wholesale Cost Component				
Municipal Taxes	4.88	4.88	0.47	0.47
Provincial Taxes	36.24	36.24	14.62[b]	38.00
Federal Taxes	32.75	32.75	31.38	34.31
Other Taxes				
Capital Taxes	0.70	0.21	-	-
Sales Tax	-	-	-	8.46
Other Provincial Taxes	2.75	-	-	-
Municipal Property and/or Franchise Tax	0.17	1.19	8.73	3.37
Downstream Income Tax[c]	2.54	4.01	1.64	-
Provincial	0.56	0.97	0.32	-
Federal	1.98	3.04	1.32	-
Total Taxes	80.03	79.28	56.84	84.61
Municipal	5.05	6.07	9.20	3.84
Provincial	40.25	37.42	14.94	46.46
Federal	34.73	35.79	32.70	34.31
		Percent of Burner-Tip Prices		
Total Taxes	42.47	47.89	60.63	65.38
Municipal	2.68	3.67	9.81	2.97
Provincial	21.36	22.60	15.93	35.90
Federal	18.43	21.62	34.89	26.51

NOTES: See Table 3.4.

minor importance. Similar allocation procedures were used for the British Columbia distribution end tax component.

Cost-of-service data were made available for Ontario by Consumers' Gas Company, the private gas utility serving the Toronto market. The utility allocated income tax on the basis of return to the rate base. Property and capital taxes were allocated according to net investment. In this study, the tax figure allocated to each customer class was estimated without distinguishing between fixed, energy, and demand charges. The total figure was then divided by customer sales volume to get a unit figure for the tax by end-use sector.

In Alberta, income and property taxes were allocated according to the rate base. The municipal revenue tax is levied as a percentage of customers' sales bills and was allocated on the basis of revenues.

The analysis of this chapter indicates that the total taxes levied do not vary greatly across the provinces. Burner-tip prices, however, are significantly higher in Eastern Canada than in the two gas producing provinces considered. Indeed, Quebec prices are roughly twice as high as Alberta prices. Transportation charges only account for part of this gap: the TCPL toll, for instance, represents just over a third of the difference between industrial prices in Calgary and Montreal. Distribution margins, in turn, account only for a small portion of the observed gap. Instead, it appears that the ABP portion of the eastern wholesale cost is the major source of the observed difference in burner-tip prices. The regulated price allows producers in Alberta to obtain higher returns on gas sales to the east than on unregulated, intraprovincial sales, and this is reflected in burner-tip prices.[4]

3.4 Other Issues

The preceding sections have identified the burner-tip prices of natural gas and their tax component. An explicit subsidy was identified in Alberta as a result of the provincial price support scheme. A number of other important tax and subsidy measures affect the natural gas industry, and will be described briefly, but the analysis of their impact on consumers and burner-tip prices is beyond the scope of this paper.

The National Energy Program introduced several programs designed to secure future supplies of petroleum and to encourage

substitution away from oil. Under the Canadian Oil Substitution Program,[5] the federal government offered to pay up to 50 percent of the cost of converting away from oil based heating systems through grants up to $800. The effects of this program are discussed in section 5.4.

The Petroleum Incentives Program (PIP), in turn, reduces certain eligible costs of firms exploring for oil or gas and may ultimately reduce finding costs. The joint product nature of oil and gas, however, makes it very difficult to establish whether or not a given expenditure is attributable to oil or gas exploration. The outcome of any exploration effort may be to uncover oil, gas or both. In Alberta and British Columbia, most recent exploration activity was "intended" to discover additional oil reserves, but associated gas discoveries will nonetheless have resulted from the PIP grants.

The gas industry also benefits from more direct subsidies: the Market Incentive Payments scheme described in section 3.1 clearly affects gas utility costs. Alberta producers contribute roughly 30 percent of the ABP on incremental volumes of gas sold to the east to this program, for a total of $78.8 million in 1984. Under the related Distribution System Expansion Program, the federal government will fund a substantial proportion of the capital costs of programs designed to expand natural gas markets.[6]

In April of 1984, the Federal and Alberta governments reached a 3-year agreement to discount incremental gas sold east of Alberta by 35 cents per gigajoule. The average level of consumption for the 2 years preceding May 1, 1984 constitutes the base used to determine incremental volumes. This discount was offered, during the second half of 1984, to certain large industrial and commercial consumers. Alberta producers contribute to this program through a charge levied against the Alberta Cost of Service. The discount is administered through quarterly rebates to consumers. The first payment under this scheme amounted to $2 million and was made in December 1984.

Further subsidies have been offered to the natural gas industry through the funding of research into transportation fuel alternatives to gasoline, fuel processing techniques, and fuel economy in all stages of the industry, but the final impacts of these expenditures are difficult to determine at this stage.

Footnotes

[1]This is possible since many of the tax and incentive schemes affecting the production of gas are paralleled in the oil industry. See section 4.1.1.

[2]The funds collected as Market Development Incentive Payments contribute to the federal government's Distribution System Expansion Program (see footnote 6).

Also, it should be noted that producers currently face the possibility of negotiating gas export prices directly subject to the floor measured by the domestic price in Toronto.

[3]The system can produce negative implicit royalties, a factor which has led to proposals for the reform of British Columbia's gas marketing system. A number of changes which will bring the B.C. regulatory environment closer to that of Alberta, with explicit royalties, an export flowback system and a modified role for the BCPC, have been initiated. The changes were announced by the British Columbia government in September 1983, based on Govier's "A Report on the Marketing of British Columbia Natural Gas."

[4]This return is reduced on "incremental" gas sales to the East. Alberta producers contribute 30 percent of the ABP on such sales. See section 3.4.

[5]See section 5.4 for a brief discussion of some of the effects of the COSP.

[6]For example, the federal government is contributing 73 percent of the capital cost of installing 10 kilometres of gas mains and 2 regulator vaults to serve B.C Hydro's customers in the Aldergrove area.

Chapter 4

FUEL OIL

4.1 From the Wellhead to the Refinery Gate

The analysis of this chapter is based on aggregate data available through the Petroleum Monitoring Agency.[1] Before proceeding to methodology and calculations, a brief overview of the pricing and taxation scheme existing in mid-1984 is presented.[2]

4.1.1 Pricing Regime

This section outlines the pricing and taxation regime as it existed during the first half of 1984. The federal-provincial energy agreement of March 28, 1985 eliminates regulated prices as of June 1, 1985. The blended price, regulated field prices, Petroleum Compensation Charge, Oil Imports Compensation, and Canadian Ownership Special charge are all eliminated under the new agreement. In addition, the PGRT will be gradually eliminated over the 1986 to 1988 period.

The pricing and taxation system for crude oil that existed in Canada in 1984 was the complex result of federal-provincial negotiations. Domestically produced crude oil generally fell under one of two wellhead pricing regimes: COOP (conventional Old Oil Price) and NORP (New Oil Reference Price). Both the COOP and NORP prices were legislated to track imported crude prices. The COOP price followed a complex formula that tied it to previous COOP levels or 75 percent of the import price, depending on the level of the import price relative to previous COOP field prices. Prices for NORP oil were adjusted on a monthly basis to track current import prices and exchange rates under a complicated block pricing structure based on density and sulphur content.

Canadian refiners paid a weighted average of COOP, NORP, and import prices. The basic rationale behind the system was to ensure that all refiners paid the same end price per barrel of crude they purchased (after adjusting for differing qualities and transportation

costs from Alberta to the refinery). This price was referred to as the blended price.

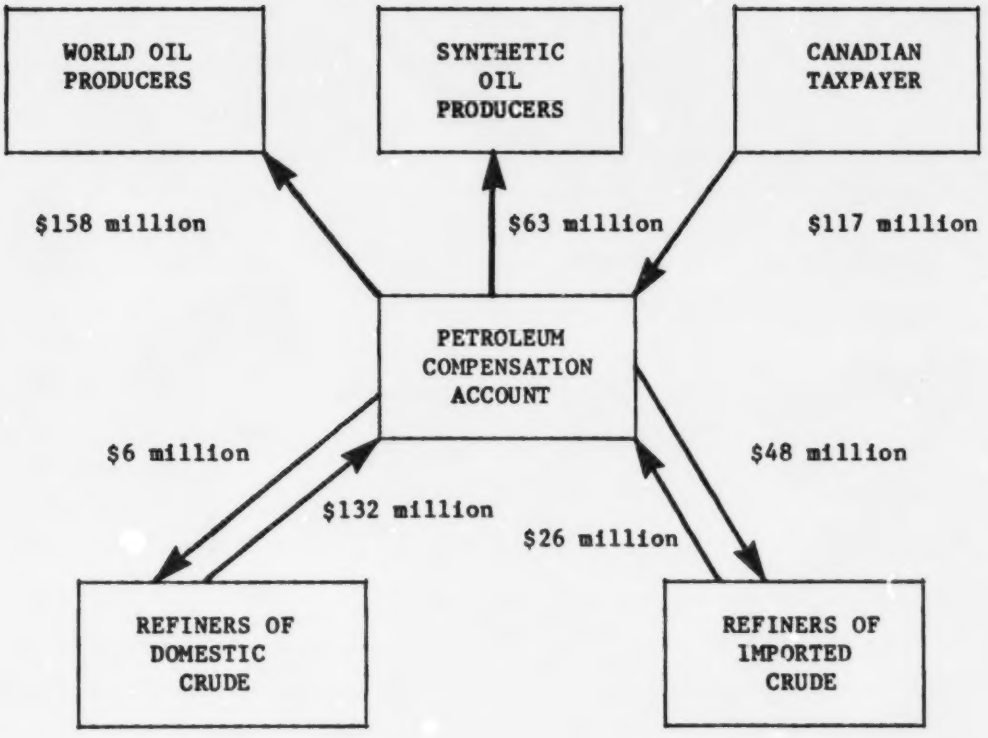
Because different refiners purchase different proportions of COOP, NORP, and imported oil, a mechanism was required to determine the level of the blended price. This mechanism was The Petroleum Compensation Account (PCA). The PCA was intended to be a zero-balance account whose receipts and disbursements average out crude costs to all refiners.

The producers of domestic crude sold to Canadian refineries received, as a wellhead price, the COOP price net of transportation costs. Producers of NORP oil then applied to the PCC account for a "NORP Supplement" which represented the difference between COOP and the quality adjusted import price. A further charge was placed against the PCC account to reimburse refiners of imported crude oil for the difference between the imported oil cost and the blended price. In order to meet the financial obligations of the PCA, a Petroleum Compensation Charge was levied against all oil refined in Canada, domestic or imported. The net effect on the refiner was that his crude costs were equal whether he refined domestic or imported crude (assuming similar qualities). The net effect on the producer has been that he received, in total, the legislated price for his COOP or NORP oil.

One further implication of this pricing structure arose when comparing the blended price to the import price for similar quality crude. Because the COOP price was below world price, when it was averaged into NORP, and import prices, the blended price remained below world levels. In June of 1984, the blended price was approximately 92 percent of the import price.[3]

The Petroleum Compensation Charge, and the COOP/NORP pricing regime as administered in mid-1984 involved subsidies or income transfers from certain segments of society to others. The PCA flows of cash that accrued for the month of June 1984, are shown in Figure 4.1. The account shows total payments to refiners of imported crude exceeded receipts by $22 million (see Table 4.1 for the geographic distribution of crude imports). Refiners of domestic crude paid a net of $126 million into the PCA. This $126 million represented a subsidy to the account from producers of COOP oil, who received a lower price for their oil than refiners paid (the difference being the PCC levy). Producers of NORP and synthetic oil received a total of $221 million in payments from the PCA. This left a deficit of $117 million for the

JUNE 1984



Total In/Out = $269 million.

SOURCE: Canada, Energy, Mines and Resources Canada, Oil Import Compensation Branch.

FIGURE 4.1: THE PETROLEUM COMPENSATION ACCOUNT

TABLE 4.1

DOMESTIC AND IMPORTED CRUDE OIL REFINED IN CANADA
JANUARY-JUNE 1984
Cubic Metres Received by Refiners:

	Domestic Crude Received	Imported Crude Received	Total Crude Received	Domestic Crude as Percent of Total
B.C.	3 978 180	-	3 978 180	100
Alberta	8 167 519	-	8 167 519	100
Saskatchewan	855 844	-	855 844	100
Manitoba	-	-	-	-
Ontario	14 135 092	413 334	14 548 426	97
Quebec	5 066 557	4 010 302	9 076 859	56
Atlantic	1 506 962	3 130 560	4 637 522	32
Canada	33 793 470	7 554 196	41 347 666	82

SOURCE: Canada, Statistics Canada, Catalogue No. 45-004, Refined Petroleum Products, June 1984.

taxpayers of Canada to contribute to the fund. This transfer of revenues from the taxpayers of Canada to oil consumers occurred (and continues until June 1, 1985) because the PCA was permitted to run a deficit. To the end of June 1984 this deficit had reached a total of 450 million dollars.[4] The increase in the PCC announced in November of 1984[5] has slowed substantially the rate of increase in the PCA deficit. Under the terms of the Western Accord, the total deficit in the PCA to June 1, 1985 will not be cleared. This means that general revenues of the Government of Canada must assume the liability.

Taxes on oil have included Crown royalties, income taxes, Petroleum and Gas Revenue Tax (PGRT), Incremental Oil Revenues Tax (IORT), Canadian Ownership Special Charge (COSC) and non-income taxes (municipal property and other taxes). These taxes and methods of quantifying them are discussed in the following section.

4.1.2 Methodological Issues

The joint products nature of the oil and gas industry makes it difficult to identify that portion of a number of taxes accruing to oil operations and that portion accruing to natural gas. Further, data for the Petroleum Monitoring Survey are presented for the industry as a whole. For these reasons, simplifying assumptions have been made.

The allocation of Crown royalties between oil and gas production volumes was made on the basis of data provided by the governments of B.C., Alberta, and Saskatchewan. Together, these three provinces account for almost 99 percent of Canadian oil and gas production as measured in the PMA survey. The Crown royalties reported in the survey for both federal and provincial governments are allocated between oil and gas on the basis of provincial data. Although this may not be accurate for federal Crown royalties, the error is likely negligible given the fact that provincial royalties account for over 99 percent of total Crown royalties.

A more difficult issue relates to the apportionment of Petroleum and Gas Revenue Tax (PGRT) and federal and provincial income taxes between oil and natural gas. The PGRT, as its name implies, is a tax applied to gross revenue from oil and gas production (net of certain royalties and expenses). The tax carried a basic $250,000 exemption to the first half of 1984.[6] Because of this exemption, smaller companies were able to shelter a greater proportion of revenues per unit of production than were larger companies. Given the fact that smaller

companies derive a larger share of revenues from gas production than do larger companies, PGRT must be split accordingly. For each of the industry groups reported in the survey, the PGRT for that group was split between oil and gas on the basis of total value of production. These dollar values are then divided by production volumes to provide per unit PGRT.

Federal and provincial income taxes have also been divided between oil and gas on the basis of their contribution to the total value of production, based on industry groups. This division will be inaccurate to the extent that the income tax system favours one product over the other through more generous deductions, etc. Non-income tax accounts for a very small proportion of total tax (approximately 2 percent) and is allocated in the same manner as income tax.

The PCC (paid by refiners into the PCA) is included as a tax, although it is simply a revenue transfer from producers to consumers. To offset the PCC, a compensation account subsidy is also included. This represents the average payment from the account. The net effect is a subsidy equal to the cumulative deficit incurred by the PCC account during the first half of 1984.

Under the terms of the Western Accord, the PCC and COSC were eliminated. As shown in Table 4.2 the net effect of this on the consumer may be minimal in terms of net level of taxation. The federal government will no longer collect these taxes, but it will no longer be required to make the payments outlined in Figure 4.1. The distribution of the benefits arising from the change will, however, have a noticeable effect.

A subsidy is also implied by the reduction in crude oil costs resulting from a blended price that is below world levels. With a blended price at 92 percent of world price, the refiner was paying approximately 8 percent less than if he had paid world price for all oil. This subsidy has not been included in the calculations of this paper.

4.1.3 Average Refinery Gate Crude Prices

Table 4.2 shows the average price refiners paid in Montreal together with a list of per unit taxes levied against crude and per

TABLE 4.2

MONTREAL REFINERY ACQUISITION
COST OF CRUDE, JUNE 1984

	$/m^3$		Percent of RAC
Acquisition Cost		229.99	
Royalty Components[a]			
Average Provincial Royalty	45.32		
Federal Royalty	0.09		
Total Royalty		45.41	19.7
Upstream Income and Property Tax			
Provincial Income Tax	8.68		
Federal Income Tax	31.82		
Total Income Tax		40.49	17.6
Non-Income Tax		1.02	0.4
Other Federal Taxes			
Petroleum Compensation Charge[b]		23.64	10.3
Canadian Ownership Special Charge[b]		7.25	3.2
Petroleum and Gas Revenue Tax[c]			
Gathering and Transmission System			
Provincial Income Tax	0.62		
Federal Income Tax	2.28		
Total Income Tax		2.90	1.3
Non-Income Tax		0.68	0.3
Total Taxes			
Municipal[d]	1.70		0.7
Provincial	54.62		23.7
Federal	16.35		37.5
Total		142.67	62.0
Less Subsidies			
PCC Subsidy[e]	33.37		14.5
Net Taxes[f]			
Municipal	1.70		0.7
Provincial	54.62		23.8
Federal	52.98		23.0
Total		109.30	47.5

SOURCES: (1) Energy Pricing News, June 1984, (2) Petroleum Monitoring Agency, Petroleum Monitoring Survey, 1984, First Six Months; (3) Canada, Energy, Mines and Resources Canada, Oil Import Compensation Branch; and (4) Company annual reports.

[a]Royalties are averaged across provinces. To the extent that any region uses crude from a particular province (Alberta for example) their average royalties are inaccurate for that region.

[b]The PCC and COSC are eliminated as of June 1, 1985.

[c]The PGRT will be eliminated over the period of January 1, 1986 to December 31, 1988.

[d]Non-income taxes are assumed to be municipal property and other taxes.

[e]This subsidy reflects compensation payments and the deficit in the PCC account that accrued in the first six months of 1984. This deficit ($402.3 million) is spread across all crude received by refineries (41.348 $10^6 m^3$) to yield a per unit charge of $9.73/m^3$. This deficit is added to the PCC of 23.64 to get the total per unit paid out of the account (on average).

[f]Two important subsidies are conspicuously absent from this table. They are exploration grants (PIP grants), and subsidies to development of oil sands technology. These two items are discussed qualitatively in section 4.4.

unit subsidies. It is important to recall that the method of presenting taxes against crude acquisition costs is adopted for pedagogical purposes only. It simply compares total taxes to the price of crude entering the refinery. There is no implication that if any of the taxes or royalties were removed that the crude costs would change. Also, the presentation is not intended to imply that the entire burden of the tax falls directly on the consumer.

Two interesting points arise from Table 4.2. First, both the federal and provincial governments earn virtually all of their revenues at the wellhead. Second, when disbursements from the PCC account have been taken into account, total provincial royalties and taxes are, on average, roughly equivalent to federal royalties and taxes. Again, this is based on average crude, including oil sands (and imports where the PCC is concerned), and does not apply to any specific crude stream.

One final comment on the results presented in Table 4.2 relates to the subsidy implied by keeping the blended price below world levels. This subsidy is not included in the table because it does not involve a cash transfer, whereas all other items in the table do. Given a Montreal crude acquisition cost of $229.99 per cubic metre and a quality adjusted import price of $250.97 per cubic metre,[7] one might conclude that the consumer is subsidized by the difference in prices. However, one must first net out the existing subsidy to taxpayers of $9.73 per cubic metre that results from the PCC deficit. If the PCC account were balanced on a month-to-month basis, the blended price (hence Refinery Acquisition Cost) would have been $9.73 higher (due to a higher PCC levy). The remaining $11.75 per cubic metre (5 percent of the blended price) represents the net subsidy to domestic oil consumers due to a blended price below world levels (remembering that the analysis refers to mid-1984).

4.2 Through the Refinery

An oil refinery transforms crude oil (and a number of other raw material inputs) into a variety of refined products. The refinery is capital intensive and allows some flexibility in the mix of feedstocks charged and of products produced. The goal of the refiner is to produce a given product mix from available inputs and to do so at minimum cost. Typically a linear programming model is used to simulate possible mixes for the refiner. The capital, feedstock and operating costs of the refinery must also be apportioned across products in order

to adequately account for these costs. A calculation referred to as a net realization is often used to compare product revenue and crude costs. It also provides a methodology for distributing the cost of crude oil across refinery output products. The basis of the method is to apportion crude costs to each product according to its price relative to other products and its share of the total volume of refinery output.

The realization calculation begins with product prices at the refinery gate and product output levels. The next step is to generate a weighted average price of all products where the weights are individual products' shares of total output. This weighted average price is referred to as a net or average realization and represents the weighted average sales revenue to the refinery per cubic metre of output. Individual product prices can then be compared to this average realization (adjusted for refinery gain) to determine realization ratios for each product. The realization ratios then represent the ratio of an individual product's price to the average product price. Average input crude costs multiplied by these ratios will give crude costs per cubic metre for each product. This will allocate crude costs between products on the basis of relative prices and will also ensure that all crude costs are recovered.

Table 4.3 presents a net realization calculation for four regions of Canada. All pricing and volume data are taken from publicly available sources. The gross margins reported represent margins available to pay all costs except crude costs. The margins reported in Table 4.3 appear high, probably because posted product prices were used.[8] For the purposes of this study, the important information in Table 4.3 is the realization ratios for light and heavy fuel oil. These ratios are combined with average crude costs to determine the crude costs to be attributed to fuel oil. These costs are presented in Table 4.4.

It is important to recall that all calculations in Tables 4.3 and 4.4 are based on publicly available product prices. Those prices are averages for a region and do not apply to individual refiners or contracts. Also, to the extent that discounts are offered, these prices do not reflect actual prices paid. For the purposes of this study, however, they are sufficiently reliable.

TABLE 4.3

REGIONAL REFINERY REALIZATIONS

	Montreal	Toronto	Edmonton	Vancouver
Product Prices ($/m^3)[a]				
Gasoline[b]	303.76	288.87	274.79	280.50
Jet Fuel[c]	285.00	277.00	255.00	268.00
Diesel	273.00	266.00	248.00	263.00
LFO	270.00	255.00	245.00	255.00
HFO[d]	208.00	185.98	176.24	182.33
Other[e]	240.75	261.00	186.30	207.50
Product Slate (proportions)				
Gasoline	0.35	0.38	0.43	0.46
Jet Fuel	0.04	0.05	0.07	0.07
Diesel	0.14	0.12	0.32	0.25
LFO	0.15	0.12	0.01	0.06
HFO	0.19	0.12	0.01	0.07
Other	0.14	0.21	0.16	0.09
Refinery Gain	1.029	1.022	1.02	1.027
Average Realization/m^3				
Product	266.95	263.28	249.13	259.80
Average Realization/m^3				
Crude	274.70	269.05	254.09	266.86
Less Average Crude Cost	229.99	229.00	221.97	226.83
Equals Gross Margins	44.71	40.05	32.12	40.03
Realization Ratios[f]				
Gasoline	1.11	1.07	1.08	1.05
Jet Fuel	1.04	1.03	1.00	1.00
Diesel	0.99	0.99	0.98	0.99
LFO	0.98	0.95	0.96	0.96
HFO	0.76	0.69	0.69	0.68
Other	0.88	0.97	0.73	0.78

SOURCES: (1) Oil Buyers' Guide; (2) Canada, Statistics Canada 45-004, Refined Petroleum Products; (3) Energy Pricing News; and other industry sources.

[a]Product prices are before discounts. Any discounts made would lower prices, lower gross margin and lower realization ratios.

[b]Average of regular leaded, regular unleaded, and premium unleaded grades, weighted by volumes.

[c]Includes naphtha and aviation gasolines.

[d]Weighted average of 1.5 percent and 3.0 percent sulphur HFO.

[e]Includes propane, butane, petrochemical feedstocks, stove oil, asphalt, coke, lubes, still gases, and other as defined in Statistics Canada 45-004.

[f]Based on average sales realization per cubic metre of crude charged.

TABLE 4.4

CRUDE COST COMPONENT OF FUEL OIL
($/m^3)

	Montreal	Toronto	Edmonton	Vancouver
Crude Cost to Refiner	229.99	229.00	221.97	226.83
Realization Ratios				
Light Fuel Oil	0.98	0.95	0.96	0.96
Heavy Fuel Oil	0.76	0.69	0.69	0.68
Crude Costs Allocated to Products				
Light Fuel Oil	225.39	217.55	213.09	217.76
Heavy Fuel Oil	174.79	158.01	153.16	154.24

4.3 Burner-Tip Prices

From the point where crude oil enters the refinery to where fuel oil is delivered to the customer, only minor taxes are levied. The downstream segment of the industry is highly competitive, with total income tax being approximately $0.63 per cubic metre of crude refined. Property taxes are also levied against the refinery and distribution system and are outlined in Tables 4.5 and 4.6. Quebec also levies an education tax. In all regions reported in this paper, light fuel oil is exempt from provincial sales tax for residential customers and heavy fuel oil is sales tax exempt for commercial and industrial users. In addition, Alberta farm users of heating oil are eligible for a subsidy of $0.07 per litre under the Alberta Farm Fuel Distribution Allowance Program.

To the extent that discounts are available from the posted price, the tax percentages reported in Tables 4.5 and 4.6 are understated. For Alberta, the $0.07 per litre farm rebate would reduce the cost of light fuel oil, reduce the provincial and total taxes as a percentage of the price, and increase the percentages for federal and municipal tax.

Again it is interesting to note that in all provinces except Quebec, the total provincial tax per litre of fuel oil is only marginally higher than the total federal tax. In Quebec, the education tax

TABLE 4.5

SELECTED TAXES AND BURNER-TIP PRICES
OF LIGHT FUEL OIL
($/litre)

	Quebec (Montreal)	Ontario (Toronto)	Alberta (Calgary)	British Columbia (Vancouver)
Crude Cost Component	0.2250	0.2180	0.2130	0.2180
Municipal Taxes	0.0017	0.0016	0.0012	0.0015
Provincial Taxes[a]	0.0535	0.0518	0.0520	0.0523
Federal Taxes	0.0519	0.0502	0.0494	0.0503
Other Taxes				
Refinery Property Tax	0.0008	0.0204	0.0020	0.0020
Marketing Property Tax	0.0025	0.0181	-	-
Quebec Education Tax	0.0086	-	-	-
Downstream Income Tax	0.0006	0.0006	0.0006	0.0006
- Provincial	0.0001	0.0001	0.0001	0.0001
- Federal	0.0005	0.0005	0.0005	0.0005
Total Taxes	0.1196	0.1427	0.1052	0.1067
Municipal	0.0050	0.0401	0.0032	0.0035
Provincial	0.0622	0.0519	0.0521	0.0524
Federal	0.0524	0.0507	0.0499	0.0508
Posted Price	0.355	0.344	0.336	0.341
		Percent of Posted Price		
Total Taxes	33.7	41.5	31.3	31.3
Municipal	1.4	11.7	1.0	1.0
Provincial	17.5	15.1	15.5	15.4
Federal	14.8	14.7	14.8	14.9

SOURCES: (1) Petroleum Monitoring Agency, Petroleum Monitoring Survey, 1984, First Six Months; (2) Petro-Canada; and (3) Energy Pricing News, various issues.

[a]Represents an average across provinces. Data for individual provinces were not available.

TABLE 4.6

SELECTED TAXES AND BURNER-TIP PRICES OF HEAVY FUEL OIL ($/litre)

	Quebec (Montreal)	Ontario (Toronto)	Alberta (Calgary)	British Columbia (Vancouver)
Crude Cost Component	0.1750	0.1580	0.1530	0.1540
Municipal Taxes	0.0013	0.0011	0.0009	0.0010
Provincial Taxes[a]	0.0415	0.0377	0.0374	0.0370
Federal Taxes	0.0403	0.0364	0.0355	0.0356
Other Taxes				
Refinery Property Tax	0.0005	0.0204	0.0020	0.0020
Marketing Property Tax	0.0025	0.0181	-	-
Quebec Education Tax	0.0086	-	-	-
Downstream Income Tax	0.0005	0.0004	0.0004	0.0004
- Provincial	0.0001	0.0001	0.0001	0.0001
- Federal	0.0004	0.0003	0.0003	0.0003
Total Taxes	0.1001	0.1141	0.0762	0.0760
Municipal	0.0046	0.0396	0.0029	0.0030
Provincial	0.0548	0.0378	0.0375	0.0371
Federal	0.0407	0.0367	0.0358	0.0359
Posted Price	0.3080	0.3130	0.3100[b]	0.3110
		Percent of Posted Price		
Total Taxes	32.5	36.5	24.6	24.4
Municipal	1.5	12.7	0.9	1.0
Provincial	17.8	12.1	12.1	11.9
Federal	13.2	11.7	11.6	11.5

SOURCES: (1) Petroleum Monitoring Agency, Petroleum Monitoring Survey, 1984, First Six Months; (2) Petro-Canada; and (3) Energy Pricing News, various issues.

[a]Represents an average across provinces. Data for individual provinces were not available.

[b]Estimate.

raises the total provincial levy substantially above the level of federal taxes.

4.4 Other Issues

The preceding sections have dealt with a number of direct taxes imposed on oil between the wellhead and burner-tip. As such, they did not deal directly with taxes or incentives to the exploration process. The impact of these incentives has been substantial, although it was not possible for the purposes of this study to quantify these incentives. A certain number of these incentives are discussed qualitatively in this section.

In the first six months of 1984, $574 million dollars[9] in Petroleum Incentives Program (PIP) grants were paid to industry by the Alberta and federal governments. The grants are paid for exploration, development, and production activities, with over 90 percent going to exploration expenditures. The final impact of such grants is difficult to determine for several reasons. A comparative analysis of future discoveries and production with and without PIP grants would be required. As announced in the Western Accord, however, PIP grants will be phased out in 1986.

The federal government, through Petro-Canada, also has a right to obtain a 25 percent working interest in any oil or gas property on Canada Lands that comes into production in 1981 or later. The option must be exercised before the property comes into production, but allows the federal government to share in production revenues without sharing in exploration and development expenses.

Further subsidies have been offered to the oil industry in federal and provincial funds expended in oil sands research and development, subsidies for conversions from oil to other fuels, subsidies to refiners or upgraders of heavy crude oil, and incentives to refinery rationalization. In each of these cases, there is no clear method of determining the final impact of the expenditures.

Footnotes

[1]Canada, Petroleum Monitoring Agency, Canadian Petroleum Industry Monitoring Survey, 1984, First Six Months, Minister of Supply and Services Canada, Ottawa, 1984.

[2]Price Waterhouse, Oil and Gas Taxation, March 31, 1984. Price Waterhouse provides an excellent detailed summary of the taxation regime.

[3]Based on prices reported in Energy Pricing News, June 1984, adjusted for quality.

[4]This represents the total deficit accrued to June 30, 1984. the fund began 1984 with a 47.34 million dollar deficit, with an additional 402.3 million accruing in the first half of 1984 (Source: Canada, Energy Mines and Resources, Oil Import Compensation Branch, Ottawa).

[5]Michael H. Wilson, Economic and Fiscal Statement, presentation by Michael H. Wilson to the House of Commons, November 8, 1984.

[6]The basic exemption was raised to $500,000 in November 1984.

[7]The quality adjustment is based on average domestic oil at 38 degree API and 0.75 percent sulphur. An adjustment of $1.70 per degree API and $1.26 per percent weight sulphur is made to adjust the average import price per cubic metre and obtain a quality-equivalent price. Imports are assumed to average 26.8 degree and 1.85 percent sulphur.

[8]Product prices represent refinery gate prices before discounts. Any discounts made would decrease prices, hence reducing gross margins.

[9]Canada, Petroleum Monitoring Agency, Canadian Petroleum Industry Monitoring Survey, 1984, First Six Months, Minister of Supply and Services Canada, Ottawa, 1984, Appendix A-6.

Chapter 5

ELECTRICITY

The structure of the electrical industry in the four provinces under study has resulted in a tax environment notably different from that which prevails in the petroleum industry. Except in Alberta, the major suppliers of electricity are Crown owned utilities. Municipal utilities distribute power to final consumers in Ontario and in certain centres in Alberta. Under Canada'a constitution, it is not lawful for one Crown to tax another. This means that the provincially owned and municipal utilities that produce and sell electric power are not subject to income tax. The federal government, in turn, does not levy any specific taxes on electricity. The direct tax structure is simple and will be identified in this chapter. Some of the problems associated with implicit subsidies and taxes which are not paid will also be discussed. Before turning to these matters, background on the utilities which produce and sell electricity is presented.

5.1 Background

Crown owned utilities producing electricity in the regions under study are amongst the largest corporations in Canada, in terms of the value of their assets.[1] Economies of scale in production and transmission, and the belief that electric power should be provided as a necessary public service and that it should help promote industrial development, explain the level of consolidation and public ownership in this industry. Hydro Quebec, B.C. Hydro and Ontario Hydro supply more than 90 percent of the electric power requirements in their respective provinces. In Alberta, the two largest suppliers of electricity are private, regulated utilities. TransAlta Utilities Corporation and Alberta Power generate more than 80 percent of the province's power. TransAlta is the largest investor owned utility in Canada and supplies more than two-thirds of Alberta's requirements. The remaining supply is provided by municipal utilities with their own generating facilities and by industrial establishments producing electricity for their own use. Industrial own generation is most important in B.C. where it accounts for 23 percent of total generation and in Quebec (15 percent). Tables 5.1 and 5.2 compare installed generating capacity across the utilities.

TABLE 5.1

GENERATING CAPACITY AND SOURCES
OF PRIMARY ENERGY

	Hydro Electric		Thermal		Nuclear		Total
	MW	% of Total	MW	% of Total	MW	% of Total	MW
Ontario Hydro	6 497	30.53	9 224	43.35	5 558	26.12	21 279
Hydro Quebec	19 555	91.80	1 746	8.20	-		21 301
TransAlta Utilities	800	21.43	2 933	78.57	-		3 733
B.C Hydro	7 489	85.50	1 271	14.50	-		8 760

SOURCE: (1) Utility Annual Reports; and (2) Ontario Hydro, Statistical Yearbook, 1983.

TABLE 5.2

SOURCES OF PRIMARY ENERGY
(GW.h)

	Ontario Hydro	Quebec Hydro	TransAlta	B.C. Hydro
Hydro	35 165	85 900	1 473	35 378
Thermal	27 906	2 400	18 068	150
Gas			6	
Coal			18 062	
Nuclear	44 342			
Net Purchases and Exchanges	7 941	34 637	(2 398)	42
Total	115 354	122 937	17 143	35 570

SOURCE: (1) Utility Annual Reports; and (2) Ontario Hydro, Statistical Yearbook, 1983.

The breakdown of capacity by the source of power shows the preponderance of hydroelectric generation in British Columbia and Quebec. Thermal generation is the source of most of Alberta's supply of electricity and most of it is coal fired. Ontario Hydro operates 79 hydraulic, fossil and nuclear fuel generating stations and generates power from these three sources in roughly equal proportions. Coal fired units provided the bulk of the fossil fuel electricity for a total of 30.4 percent of the power made available to Ontario Hydro's customers.

The structure of the transmission and distribution stages of the industry varies somewhat across the provinces. Hydro Quebec and B.C. Hydro are virtually the sole retail distributors in their provincial markets. Ontario Hydro acts as the major source of wholesale power to over three hundred municipal utilities which, in turn, supply retail power. The Crown corporation also sells power directly to over 100 large industrial customers and to approximately 768,500 rural customers in regions which are not served by municipal utilities.

A central body made up of utility representatives, the Electrical Utilities Planning Council, coordinates the planning of generation and transmission facilities in Alberta. Most of the transmission facilities are owned by TransAlta Utilities Corporation which sells power directly to over 275,000 rural, residential, and industrial customers. The City of Calgary Electric system accounts for roughly 30 percent of TransAlta's total sales. Table 5.3 summarizes information on the major utilities' sales and volumes by end use sector. Clearly, Hydro Quebec and Ontario Hydro have the largest operations.

Electricity prices are regulated in Canada, but here again the system varies slightly across the provinces. In general, the utilities are required to charge rates which are determined on the basis of the total cost of providing power to their customers. Ontario Hydro sets the rates for its wholesale and indirect customers following recommendations drawn up by the Ontario Energy Board. Thus, the corporation has the final authority over prices. It also acts as a regulatory authority for the municipal utilities who must seek approval with Ontario Hydro for the retail rates they charge.

Unlike B.C. Hydro and Ontario Hydro, Hydro Quebec's proposed tariffs are discussed in a parliamentary commission and approved by the Quebec cabinet. Hydro Quebec's dominance of the distribution system facilitates rate setting which does not vary in different areas of the province.

TABLE 5.3

ELECTRICITY SALES AND REVENUES[a]
BY END USE SECTOR
(1984)

	Sales (GW.h)	Revenues ($10^6$$)
Residential		
Ontario Hydro[b]	18 083	728
Hydro Quebec	36 600	1 453
TransAlta Utilities	2 056	141
B.C. Hydro	9 607	448
General Service[c]		
Ontario Hydro	-	-
Hydro Quebec	19 600	864
TransAlta	735	68
B.C. Hydro	9 957	425
Industrial		
Ontario Hydro	14 462	536
Hydro Quebec	31 200	837
TransAlta	7 386	283
B.C. Hydro		
Export		
Ontario Hydro	11 115	432
Hydro Quebec	22 500	631
TransAlta		
B.C. Hydro	2 834	75
Wholesale Power and Other[d]		
Ontario Hydro	71 047	2 503
Hydro Quebec	14 600	332
TransAlta	6 413	207
B.C. Hydro	10 045	282
Total Power		
Ontario Hydro	114 706	4 199
Hydro Quebec	124 500	4 117
TransAlta	16 590	699
B.C. Hydro	31 903	1 230

SOURCES: (1) B.C. Hydro. Annual Report, 1984; (2) Ontario Hydro's 1984 rate application--the Alberta and Quebec figures were provided by the utilities.

[a]Figures are 1984 projections, except for B.C Hydro sales and revenues which are actual numbers drawn from the Utility's 1983-1984 annual report.

[b]The Ontario figure represents direct sales to rural customers.

[c]Includes B.C. Hydro industrial sales.

[d]The figure for B.C. Hydro includes sales to Washington Water Power and transmission sales. The figures for Ontario Hydro represent sales to Municipal Utilities. The TransAlta figure includes exterior lighting, irrigation and sales to the City of Calgary.

Since production costs differ across suppliers in Alberta, legislation was introduced in 1981 to bring a degree of uniformity to electricity rates across the province. The legislation established the Alberta Electrical Energy Marketing Agency which purchases power from TransAlta utilities, Alberta Power and Edmonton Power. The agency sets a province-wide wholesale price for each of the residential, industrial and general service consumer groups and then resells the power to the utilities for distribution. This has the effect of averaging generation and transmission costs. Distribution costs are not considered by the Agency. The system has been phased in gradually to protect consumers of the lower cost producers from abrupt rate increases.

5.2 General Issues

The preceding section described an industry dominated by Crown owned utilities which do not pay income taxes under the Canadian constitution. This section discusses some of the problems associated with the evaluation of the implicit subsidies and of the taxes which are not paid in the electricity industry.

In addition to the income tax exemption, Crown utilities have benefited from loan and bond guarantees offered by provincial governments. By affording the utilities easier access to capital markets on favourable terms, these guarantees may have had the effect of lowering the utilities' interest costs. It is difficult to establish the extent to which debt costs would be higher in the absence of loan guarantees, though, since utility bond rates are also determined by many other factors. Historical rates of return, debt structure, market structure and pricing and the perceived ability of a borrower to meet potential competition are only some of the factors which influence lenders' assessments of the risk premium required on a utility loan. It would thus be incorrect to quantify the interest savings by simply comparing utility bond rates with those offered on contemporaneous issues with similar maturity dates. Business and financial risk differentials make the task much more complex, and beyond the scope of this study. Nonetheless, the loan guarantees have enabled Hydro Quebec, Ontario Hydro, and B.C Hydro to operate with a higher ratio of debt to total capital than the private regulated utilities in the electricity or in the other sectors. Indeed, TransAlta's ratio of debt to total capitalization is around 62 percent including preferred shares, compared to 75 percent for Hydro Quebec, 85 percent for Ontario Hydro and over 88 percent for B.C. Hydro.

Preferential interest rates serve to lower the utilities' costs and hence their revenue requirements through another channel. The utilities' capital assets may be undervalued as a result of the technique employed to capitalize the cost of ongoing construction programs. To the extent that the utility's bond rate is used to assign a financial cost to the unproductive funds tied up in the construction project, the capitalized cost may be biased downward, as will the return to capital which forms part of the utility's revenue requirement.

Other problems arise from the dependence of the utilities' financial and investment decisions on the tax structure. A new tax regime could produce tax avoidance behaviour. For example, when interest payments are deductible from taxable income, an incentive to borrow more heavily is created. The removal of a loan guarantee might have the opposite effect. Thus, it would not be appropriate to comment on the pricing effect of changes in borrowing costs or fiscal regimes (the introduction of corporate income taxes, to the electricity industry, for instance) without first determining the reaction of the utilities. There is a complex behavioural relationship between taxation levels and consumer prices. In the face of these difficulties, these subsidies are not quantified here. The analysis will be confined to directly measurable taxes and subsidies, as well as to the prices actually paid by consumers.

5.3 Methodological Issues

The sectoral prices of electricity developed in this chapter are averages drawn for the most part from utility rate schedules in effect in the first half of 1984. The rate structures may contain seasonal and time of use differences, but these have been smoothed over to yield a representative rate for each customer class.

Though the electricity industry is not subject to federal energy taxes, a number of explicit provincial and municipal taxes enter into electricity prices. The fuel costs associated with the generation of electricity generally comprise a tax component. Except in Quebec, water rentals are charged by the provincial governments for the use of water in the production of hydro electricity.[3] When fossil fuels such as coal are used, royalty payments must be made to the owner of the resource rights and Crown royalties are thus included in the tax component of electricity prices. In Ontario, uranium royalties constitute a very small portion of nuclear fuel costs.

The tax component of fuel cost is allocated to the different rate groups on the basis of sales, since it represents an "energy charge" which varies with consumption. Wherever possible, capital and/or property taxes paid to municipal and provincial governments are allocated in a manner consistent with the way in which the tax assessments are made. (Generally, these taxes vary with the value of the net fixed assets.) To do so, detailed rate base information is required. As in the case of natural gas distribution, the costs must first be allocated to different functions, i.e., generation, transmission and distribution. Functionalized costs are then separated into customer costs, which are related to the number of customers (e.g., metering) regardless of load; demand costs, which are associated with the capacity necessary to meet customer deliveries; and finally, energy costs which vary with power usage. Customer costs can then be allocated on the basis of the number of consumers in each rate group, energy costs can be allocated according to customer deliveries and demand costs can be allocated on the basis of peak demand.

In Alberta, the tax component of the wholesale price of electricity comprises income taxes, Crown coal royalties, capital and property taxes. The federal government rebates 95 percent of the federal corporate income tax to the provinces under the Public Utilities Income Tax Act. The Province of Alberta rebates this amount as well as 100 percent of the provincial income tax to the utility. However, the income tax rebates are not represented in TransAlta's rate structures.[4]

The Crown royalties on coal were allocated across TransAlta's different rate classes, including the City of Calgary, on the basis of power supplied at the generator. Property taxes and the Electric Power and Pipeline tax were allocated to TransAlta's customers in proportion to capital investment. Because of the way in which income taxes are rebated in Alberta, income taxes were simply allocated on the basis of the subtotal of all other costs, rather than in the usual manner, i.e., according to the rate base, or to return. The rebate is then treated as an explicit subsidy which lowers the effective retail price to consumers of the City of Calgary Electric System.

In most other cases, detailed rate base information was not made available and revenues are used as the basis for allocating property, capital, and sales taxes. It is assumed that revenues provide a reasonable indication of where costs are incurred, but

obviously the methodology will be inaccurate to the extent that cross-subsidization occurs.

5.4 End-Use Prices

Table 5.4 summarizes the results of this chapter. Tables 5.5 to 5.7 provide a more detailed analysis by end-use sector.

Consumer prices are, in general, highest in British Columbia, though they would be highest for some sectors in Alberta in absence of the income tax rebate. The average sectoral prices for B.C., shown in Table 5.4 incorporate a 6.5 percent increase designed to meet cost increases associated with fixed assets committed in past years, as well as rising debt costs attributable to a weak Canadian currency. B.C. Hydro's costs are particularly sensitive to changes in the value of the dollar because a large fraction of its debt is denominated in U.S. currency. The corporation's financial costs are, in turn, the largest component of B.C. Hydro's revenue requirement.[5]

Non-industrial customers in British Columbia must also pay 7 percent sales tax. Residential customers pay a "municipal transit levy" equivalent to a flat charge of $1.25 on monthly electricity accounts. The municipal transit levy contributes to the funding of Vancouver's public transit system.

The prices charged to TransAlta's customers are affected by the Electrical Energy Marketing Agency, as discussed in section 5.1. During the first year of the marketing system, consumers of the lowest cost utility were fully shielded from rate increases which arose from TransAlta's repurchase of electricity at the higher, provincial wholesale rate set by the Public Utilities Board. The amount of shielding is decreasing though, and TransAlta has charged a "special levy" to its customers to meet this additional cost. In 1984, the special levy amounted to 1.9 percent of sales revenue from January until June. It represents a transfer of income from consumers of low cost electricity to consumers of higher cost electricity.

The rate paid by consumers of urban municipalities in Ontario incorporates a similar transfer to rural consumers. Legislation passed by the Province of Ontario in 1981 limited the disparity between rates charged to municipal and year round rural residential customers to a maximum of 15 percent despite the high rural distribution costs. The Rural Rate Assistance program affects the allocation of the revenue

TABLE 5.4

ELECTRICITY BURNER-TIP PRICE
AND TAX COMPONENT[a]

	Quebec	Ontario	Alberta[b]	British Columbia
Residential Burner-Tip Price (BTP)	4.76	4.09	5.50	5.45
Provincial tax				
¢/kW.h	0.65	0.07	0.12	0.47
% of BTP	13.60	1.71	2.13	8.62
Municipal tax				
¢/kW.h	0.09	0.07	0.62	0.60
% of BTP	1.80	1.71	11.20	11.00
Federal tax				
¢/kW.h	-	-	0.02	-
% of BTP	-	-	0.36	-
Total tax				
¢/kW.h	0.74	0.14	0.76	1.07
% of BTP	15.40	3.42	13.69	19.62
Commercial Burner-Tip Price	4.79	4.23	4.89	5.97
Provincial tax				
¢/kW.h	0.73	0.07	0.12	0.84
% of BTP	15.15	1.65	2.39	14.08
Municipal tax				
¢/kW.h	0.10	0.08	0.55	0.47
% of BTP	2.04	1.89	11.25	7.87
Federal tax				
¢/kW.h	0	0	0.02	0
% of BTP	0	0	0.41	0
Total tax				
¢/kW.h	0.82	0.15	0.69	1.31
% of BTP	17.19	3.54	14.05	21.95
Industrial Burner-Tip Price	2.68	3.50	4.01	4.54
Provincial tax				
¢/kW.h	0.19	0.07	0.12	0.75
% of BTP	7.09	2.00	2.91	16.54
Municipal tax				
¢ kW.h	0.06	0.06	0.46	0.36
% of BTP	2.23	1.71	11.47	7.93
Federal tax				
¢/kW.h	0	0	0.02	0
% of BTP	0	0	0.50	0
Total tax				
¢/kW.h	0.13	0.25	0.60	1.11
% of BTP	3.71	9.32	14.88	24.47

[a]The tax figures do not include provincial and federal sales tax on manufactured inputs or custom duties paid on imported inputs. Percentages have been calculated on the basis of tax figures before rounding.

[b]Figures are net of income tax rebate.

TABLE 5.5

SELECTED TAXES AND BURNER-TIP PRICES
RESIDENTIAL SECTOR
(¢/kW.h)

	Quebec (Montreal)	Ontario (Toronto)	Alberta[a] (Calgary)	British Columbia (Vancouver)
Burner-Tip Price	4.76	4.09	6.16	5.45
Net of rebate	-	-	5.50	-
Fuel Cost Component				
Water rentals	-	0.03	0.00	0.47
Royalties[b]	-	0.04	0.12	-
Income Tax				
Income taxes	-	-	0.68	-
Alberta income tax rebate	-	-	0.66	-
Other Provincial Taxes				
Capital & property	0.15	-	0.10	-
Sales tax	0.36	-	-	0
Quebec dividends	0.14	-	-	-
Municipal taxes				
Property or Revenue	0.09	0.03	0.61	-
B.C. transit levy	-	-	-	0.16
Payments in lieu of taxes	-	0.04	-	0.44
Total Provincial Taxes	0.65	0.07	0.12	0.47
% of burner-tip price	13.60	1.71	1.89	8.62
% of net price	-	-	2.13	-
Total Municipal Taxes	0.09	0.07	0.62	0.60
% of burner-tip price	1.80	1.71	10.00	11.00
% of net price	-	-	11.20	-

SOURCES: (1) B.C. Hydro 1984 Rate Application; (2) Ontario Hydro 1984 Rate Application; (3) Data for Quebec and Alberta provided by the Utilities; and (4) Ontario Hydro Statistical Yearbook, 1983.

[a]See Table 5.4 for federal taxes paid in Alberta.

[b]Ontario royalty figures are based on average Saskatchewan coal royalties and average royalties rate paid by Eldorado Nuclear Ltd. on uranium. They may overstate the actual values because an accurate breakdown of fuel costs between the value of the volumes used, transports, storage and handling costs, etc. was not available. Also, the water rental figure does not incorporate the increased rate which became effective in June 1984.

TABLE 5.6

SELECTED TAXES AND BURNER-TIP PRICES
INDUSTRIAL SECTOR
(¢/kW.h)

	Quebec (Montreal)	Ontario (Toronto)	Alberta[a] (Calgary)	British Columbia (Vancouver)
Burner-Tip Price	2.68	3.50	4.66	4.54
Net of rebate	-	-	4.01	-
Fuel Cost Component				
Water rentals	-	0.03	0.00	0.47
Royalties[b]	-	0.04	0.12	-
Income Tax				
Income taxes	-	-	0.68	-
Alberta income tax rebate	-	-	0.65	-
Other Provincial Taxes				
Capital & property	0.10	-	0.10	-
Sales tax	0	-	-	0.28
Quebec dividends	0.09	-	-	-
Municipal taxes				
Property or Revenue	0.06	0.02	0.46	-
B.C. transit levy	-	-	-	0
Payments in lieu of taxes	-	0.04	-	0.36
Total Provincial Taxes	0.19	0.07	0.12	0.75
% of burner-tip price	7.09	2.00	2.51	16.54
% of net price	-	-	2.91	-
Total Municipal Taxes	0.06	0.06	0.46	0.36
% of burner-tip price	2.23	1.71	10	7.93
% of net price	-	-	11.47	-

SOURCES: (1) B.C. Hydro 1984 Rate Application; (2) Ontario Hydro 1984 Rate Application; (3) Data for Quebec and Alberta provided by the Utilities; and (4) Ontario Hydro Statistical Yearbook, 1983.

[a]See Table 5.4 for federal taxes paid in Alberta.

[b]Ontario royalty figures are based on average Saskatchewan coal royalties and average royalties rate paid by Eldorado Nuclear Ltd. on uranium. They may overstate the actual values because an accurate breakdown of fuel costs between the value of the volumes used, transport, storage and handling costs, etc. was not available. Also, the water rental figure does not incorporate the increased rate which became effective in June 1984.

TABLE 5.7

SELECTED TAXES AND BURNER-TIP PRICES
COMMERCIAL SECTOR
(¢/kW.h)

	Quebec (Montreal)	Ontario (Toronto)	Alberta[a] (Calgary)	British Columbia (Vancouver)
Burner-Tip Price	4.79	4.23	5.54	5.97
Net of rebate	-	-	4.89	-
Fuel Cost Component				
Water rentals	-	0.03	0.00	0.47
Royalties[b]	-	0.04	0.12	-
Income Tax				
Income taxes	-	-	0.68	-
Alberta income tax rebate	-	-	0.65	-
Other Provincial Taxes[c]				
Capital & property	0.17	0.03	0.10	-
Sales tax	0.40	-	-	0.37
Quebec dividends	0.16	-	-	-
Municipal taxes				
Property or Revenue	0.10	0.04	0.55	-
B.C. transit levy	-	-	-	0
Payments in lieu of taxes	-	0.04	-	0.47
Total Provincial Taxes	0.73	0.07	0.12	0.84
% of burner-tip price	15.15	1.65	2.12	14.08
% of net price	-	-	2.39	-
Total Municipal Taxes	0.10	0.08	-	0.47
% of burner-tip price	2.04	1.89	10	7.87
% of net price	-	-	11.25	-

SOURCES: (1) B.C. Hydro 1984 Rate Application; (2) Ontario Hydro 1984 Rate Application; (3) Data for Quebec and Alberta provided by the Utilities; and (4) Ontario Hydro Statistical Yearbook, 1983.

[a]See Table 5.4 for federal taxes paid in Alberta.

[b]Ontario royalty figures are based on average Saskatchewan coal royalties and average royalties rate paid by Eldorado Nuclear Ltd. on uranium. They may overstate the actual values because an accurate breakdown of fuel costs between the value of the volumes used, transport, storage and handling costs, etc. was not available. Also, the water rental figure does not incorporate the increased rate which became effective in June 1984.

requirement rather than its total amount. A portion of specific rural distribution cost is allocated to all consumers, thereby reducing rural rates. In 1984 the subsidy to rural customers amounted to $60 million dollars, which translated to a cost of 0.0578 cents per kilowatt hour for Toronto Hydro's customers or roughly 1-1/2 to 2 percent of the rates charged to municipal customers.

Burner-tip prices are lowest for industrial consumers in Quebec. They are exempt from the 9 percent sales tax affecting other electricity consumers in that province and they are also the beneficiaries of a significant rate discount program. The latter is designed to encourage the consumption of Hydro Quebec's surplus power and increase its share of the industrial heavy fuel market. (Existing firms receive a discount equal to 65 percent of the difference between the firm's current monthly bill and a "reference bill" equal to the highest monthly consumption recorded during 35 consecutive consumption periods.) All of "new" industrial firm consumption is subject to a 50 percent discount. The program remains effective until 1991--though the size of the discount declines progressively to 10 percent as the utility's surplus decreases. The discount program and the moderate rate increase adopted in 1984 form part of Hydro Quebec's plan to keep the price of electricity below the price of oil until 1988.

B.C. Hydro administers a similar discount program to industrial consumers in order to mitigate its excess capacity problem. For a year beginning in July 1983, industrial consumers benefited from a "Block recovery rate," whereby consumers received reduced rates for loads over and above the previous twelve month's consumption. Large industrial customers received surplus electricity at an approximate 30 percent discount. By March 31, 1984, the program generated an additional load of 190 million kilowatt-hours which represents around $40 million in revenue.

The variation in the tax component of burner-tip prices across provinces is significant. Except in Alberta, municipal taxes represent a very small portion of total taxes. In all customer classes, the calculations indicate that Ontario's taxes are just over a tenth of the value of British Columbia' taxes. The major differences are attributable to the tax component of fuel costs. British Columbia's water rental rate exceeds the total charge for water rentals and royalties in each of the other provinces. (The British Columbia rate is also greater than the rate of water rentals per unit of hydrdoelectric power sold in Ontario or Albera, respectively.) The gap is further explained

by the fact that Ontario does not levy a sales tax or a municipal charge comparable to Alberta's 10 percent revenue tax. Ontario levies almost no taxes at the distribution end.

Despite the absence of water rentals in Quebec, the tax component of non-industrial burner-tip prices is relatively high. This is because of the 9 percent sales tax and the dividends paid by Hydro Quebec to the provincial government. The tax component of industrial prices is very low, however, as a result of the sales tax exemption. Industrial consumers in Quebec, moreover, pay the lowest burner-tip prices of all regions and classes considered. It should be noted, that the dividend charge varies greatly from year to year. A total of $60 million were paid out in 1983 compared to a payment of $150 million in 1984. The tax depends on Hydro's Quebec's financial performance in a given year and does not form part of the utility's revenue requirements.

It appears, then, that the provinces have chosen to levy taxes against burner-tip prices in a different manner and to a different extent. British Columbia's provincial taxes are high and levied principally through water rentals which do not vary across customer classes, and through a sales tax. In Quebec, the provincial government collects most of its revenue through a sales tax, and, in 1984, through dividends. Municipal taxes account for much of Alberta's taxes, and a much smaller portion of Ontario's taxes, while provincial taxes in that province are also low.

5.5 Other Issues

Electricity prices are affected by government policies other than direct taxes or subsidies. These policies are in such diverse areas as electricity exports, subsidies for conversion from oil to electricity, and government investments in development or application of new generation technologies. Government approval of electricity exports as a means of eliminating surplus power may dampen domestic electricity rate increases in those provinces with excess installed capacity. Planning decisions based on a series of overly optimistic load forecasts have made the problem particularly acute in B.C., Ontario and Quebec, where the utilities have developed aggressive strategies to increase their markets. In British Columbia, for example, net export revenues from surplus sales are charged directly against revenue requirements for domestic sales. Whereas the cost of generating surplus electricity is less than 0.5 cents per kilowatt

hour, (roughly the unit cost of water rentals). B.C. Hydro has obtained export selling prices of 4 cents (U.S.) per kilowatt hour in the past. More recently, they have ranged between 1 and 2 cents per kilowatt hour (U.S.).

Consumers' fuel choice decisions depend not only on current fuel prices, but on the capital costs and efficiency of different heating systems, as well as their expectation of future fuel prices. Thus, research programs geared towards the enhancement of the efficiency of heating systems, and programs affecting capital costs such as the "off oil policies" are relevant to the consumers fuel decisions.

Electricity was forecast to play a major role in the National Energy Program's policy of substitution away from oil. The COSP induces house-owners and businesses to convert away from oil heating through a system of taxable grants amounting to a maximum of $800 or 50 percent of the cost of converting to electricity, gas, or some other renewable source of power. Provincial Crown corporations were encouraged to undertake self-financing efforts towards the connection of new electricity customers. The previous sections of this chapter indicated that a number of the utilities under study have indeed encouraged the increased use of electricity through direct conversion grants. In 1983, some 120,000 conversions from oil heating systems to electricity occurred. They represented 44 percent of total conversion, compared to 28 percent for natural gas. Most of the electricity conversion occurred in Quebec, where they represented 69 percent of total switching, versus 24 percent in Ontario. By contrast, roughly 90 percent of the conversions which occurred in British Columbia in 1983 were to natural gas. Included in these figures are conversions to the hybrid electrical oil systems which are made particularly attractive in Ontario and Quebec. The federal government has decided to cancel the COSP as of March 31, 1985, however, in the hope that the utility administered programs would persist, and that relative prices would act as a sufficient incentive for conversion.

Hydro Quebec also administers its own "off oil" substitution program. Discounts and interest free loans for conversion to a dual energy system combining oil and electrical energy are offered under a "Heat Sale Plan." The conversion program initially applied to single family units, but the grants were extended to multi-family dwellings until the end of 1984. By the end of 1983, $39 million were paid out

for the conversion of single family units to dual energy--in the form of $650 grants. Multiple unit dwellings receive discounts ranging from a $1,250 to $3,850 for a total of $35 million. The interest free loans are available to institutions only.

The nuclear industry is also affected by cost sharing arrangements and important subsidies. Under the Pickering Agreement between Ontario Hydro, Atomic Energy of Canada Limited (AECL), and the Province of Ontario, the three parties agreed to share the capital costs of constructing the nuclear powered Pickering NGS Units 1 and 2. They also share proportionally in a "pay back" reflecting the difference in unit costs between the Pickering units and coal-fired units. Ontario Hydro transfers a portion of the operating cost savings to the other parties of the agreement. At the end of 1983, the total cumulative "payback" amounted to 709 million dollars and roughly 65 percent of this total was paid to AECL and the Province of Ontario by Ontario Hydro.

In general, the federal government has provided substantial funds for research and development related to the CANDU Heavy water reactor and the assessment of uranium reserves. It has also provided financial support for the expanded use of nuclear energy power through AECL. The Canadian Electrical Association R & D program and the Electric Power Research Program involve research in all forms of electric generation, transmission, distribution, and uses. Here again, the link between research incentives, electricity production costs, and consumer prices are complex and cannot be readily quantified.

Footnotes

[1]Hydro Quebec is ranked first, Ontario Hydro second, and B.C Hydro fifth. In 1983, their total assets were valued as follows (in millions of dollars):

Hydro Quebec	$25,199
Ontario Hydro	23,194
B.C. Hydro	9,593

(based on assets as reported by the Financial Post 500, Summer, 1984 and update's to March 1984 for B.C. Hydro).

[2]This information is drawn from the Utilities' annual reports.

[3]The determination of the "correct" value of water rentals is indeed problematic and it is often argued that the failure to assign a cost equivalent to the "social opportunity cost" of water utilization results in a substantial subsidy to consumers of hydroelectricity. Since we confine our attention to directly measurable taxes and subsidies in this study, we do not attempt to evaluate the social opportunity cost or any resulting subsidy.

[4]Changes to the Alberta Electric Energy Marketing Agency stipulate that the price set by the AEEMA is a "deemed cost of power" to the utilities which should be blended into the base customer rates as of March 1985. The new regulations will result in three provincial upstream prices: a residential rate, which will include rural service, a general service rate and a large industrial user rate.

[5]Since fiscal 1982, finance charges will have increased from 32 percent to a projected 43 percent in fiscal 1986. (B.C Hydro's 1984 Rate Application.)

APPENDIX A

DATA SOURCES

Appendix A

DATA SOURCES

Alberta. Department of Energy and Natural Resources. Mineral Revenues Division.

British Columbia Ministry of Energy, Mines and Petroleum Resources. Mineral Revenue Branch.

British Columbia Petroleum Commission.

Canada. Energy, Mines and Resources. Oil Import Compensation Branch.

City of Calgary Electric System. Corporate Planning Division.

Gaz Metropolitain. Section: Affaires de Reglementation.

Hydro Quebec. Service Tarification Commercialisation.

Imperial Oil. Marketing Department in Toronto.

Ontario. Department of Finance. Sectoral and Regional Policy Division.

Petro-Canada. Corporate Planning Department.

Saskatchewan. Ministry of Natural Resources. Mineral Revenues.

Toronto Hydro. Rates Section.

TransAlta Utilities. Engineering and Economics.

APPENDIX B

CONVERSION EFFICIENCY ASSUMPTIONS

TABLE B.1

CONVERSION EFFICIENCY ASSUMPTIONS[a]

Sectors	Natural Gas	Oil	Electricity	Coal
Residential	0.70	0.65	1.00	0.50
Commercial	0.78	0.75	1.00	0.65
Contract	0.85	0.87	1.00	0.87
Interruptible	0.85	0.87	1.00	0.87

SOURCE: These efficiency figures are based on EMR data and discussions with utility representatives.

[a]Efficiency is here defined as the ratio of useable energy to energy entering the equipment. It is a measure of energy loss in the combustion process.

BIBLIOGRAPHY

Alberta. "Alberta Corporate Income Tax Act." Chapter A-17 as amended to June 1, 1982. Edmonton: Queen's Printer, 1980.

_____. "Natural Gas Rebates Act." Chapter N-5, Revised Statutes of Alberta. Edmonton, Queen's Printer, 1980.

_____. Alberta Energy and Natural Resources. Energy Statutes and Regulations. Alberta Energy and Natural Resources, 1984.

B.C. Hydro. Annual Report, 1983-1984.

Brannon, Gerald M., ed. Studies in Energy Tax Policy. Cambridge, Massachusetts: Ford Foundation, 1975.

_____. Energy Taxes and Subsidies. Cambridge, Massachusetts: Ballinger Publishing Company, 1979.

British Columbia Hydro and Power Authority. 1984 Rate Application: Electric Service Requirements, Volume 1, Vancouver, 1984.

_____. 1984 Rate Application: Electric Service Requirements, Volume 2: "Prepared Testimony and Witnesses." Vancouver, 1984.

CCH Canadian Limited. Canadian Energy News, Volume III, 1984, various issues.

Canada. Economic Council of Canada. Connections. Ottawa: Supply and Services, January 1985.

_____. Energy, Mines and Resources Canada. Agreement to Amend the Memorandum of Agreement of September 1, 1981 between the Government of Canada and the Government of Alberta Relating to Energy Pricing and Taxation. Ottawa: Energy Mines and Resources Canada, June 30, 1983.

_____. Energy Mines and Resources Canada. Economic and Policy Analysis Sector. Social Studies Branch. Draft Working Paper. "Energy Reference Cost Premiums." Energy, Mines and Resources, June 6, 1980.

_____. Energy, Mines and Resources Canada. "Electricity in Canada Update 1983." Paper presented to the Canadian Electrical Association, Spring 1984.

_____. Energy, Mines and Resources Canada. Financial and Fiscal Analysis. "Petroleum Fiscal Systems in Canada." Energy, Mines and Resources, October 1983.

_____. Energy, Mines and Resources Canada. Memorandum of Agreement between the Government of Canada and the Government of Alberta Relating to Energy Pricing and Taxation, 1981-09-01. Ottawa: Energy, Mines and Resources Canada, September 1, 1981.

_____. Energy, Mines and Resources Canada. The National Energy Program, 1980. Ottawa: Supply and Services, 1980.

_____. Energy, Mines and Resources Canada. The National Energy Program, Update 1982. Ottawa: Supply and Services, 1982.

_____. Energy, Mines and Resources Canada. The Petroleum Incentives Program. Ottawa: Supply and Services, 1981.

_____. Energy, Mines and Resources Canada. Office of Research and Development. 1983 Guide to Research and Development Activities Resulting from the National Energy Program of the Government of Canada. Ottawa: Energy, Mines and Resources Canada, 1983.

_____. Energy, Mines and Resources Canada. The Western Accord: An Agreement between the Governments of Canada, Alberta, Saskatchewan and British Columbia on Oil and Gas Pricing and Taxation. Ottawa: Energy, Mines and Resources Canada, March 28, 1985.

_____. Petroleum Monitoring Agency. Canadian Petroleum Industry Monitoring Survey, 1984, First Six Months. Ottawa: Minister of Supply and Services Canada, 1984.

_____. Statistics Canada. Electricity Bills for Domestic, Commercial and Small Power Service. Catalogue No. 57-203. Ottawa: Supply and Services, 1984.

_____. Statistics Canada. Quarterly Report on Energy Supply-Demand in Canada, Catalogue No. 57-003, 1984-II.

_____. Statistics Canada. Refined Petroleum Products, Catalogue No. 45-004, June 1984.

Canadian Western Natural Gas Company Limited. "Testimony, Rates, Cost Analysis Update." From the 1984 Rate Application, June 1983.

_____. "Letter to the Public Utilities Board Re: August 1, 1983 Changes in Cost of Gas Supply." July 29, 1983.

_____. "Letter to the Public Utilities Board Re: February 1, 1984 Increase in Cost of Gas Supply."

City of Calgary. Financial Report, 1983.

Coal Age, May, September, and October 1984 issues.

Consumers' Gas Company Ltd. "1984 Rate Application: E.B.R.O 395 Exhibit Numbers Q4 and Q5." May 1983.

Eldorado Nuclear Limited. Annual Report, 1983.

Energy Pricing News. Corpus, 1984, Volume 4, various issues.

Gary, James H. and Handwerk, Glenn E. Petroleum Refining. New York: Marcel Dekker Inc., 1975.

Gaz Metropolitain Inc. Annual Report, 1983.

Gaz Metropolitain Inc. "Requete de Gaz Metropolitain, Inc. a la Regie de l'Electricite et du Gaz. Cause Tarifaire 1984, no. 2945-83." September 1983.

Holland, E. N., Schulli, G. R. and Kemp, R. M. Canadian Taxation of Oil and Gas Income. Calgary: CCH Canadian Limited, 1981.

Hydro Quebec. Annual Report, 1983.

_____. "Memoire sur la Tarification Propeosee pour 1984." Decembre 1983.

InterProvincial Pipelines. Annual Report, 1983.

McLeod, Young, Weir. Bond and Money Market Letter, 1983, various issues.

Nova, An Alberta Corporation. Annual Report, 1983.

Ontario Hydro. Annual Report, 1983.

_____. "Electricity Rates Proposed for 1984: Municipal Utilities and Direct Industrial Customers." Submission to the Ontario Energy Board. Toronto, 1983.

_____. Ontario Hydro Statistical Yearbook, 1983. Supplement to the Seventy Sixth Annual Report. Toronto, 1984.

Ontario. Ministry of Energy. "Energy Note: Natural Gas Pricing in Ontario." Revised and Updated. Toronto, February 1984.

_____. Ministry of Energy. Ontario Energy Review. Third Edition. Toronto: 1983.

Oil Buyer's Guide, Volume 14, Lakewood, New Jersey, various issues.

Price Waterhouse. Oil and Gas Taxation. March 31, 1984.

The Royal Bank of Canada. Global Energy Mineral Group, The North American Natural Gas Industry, 1984.

TransCanada Pipelines Limited. "Application by TransCanada Pipelines Limited Pipelines Limited Pursuant to Sections 50, 51 and 53 of the National Energy Board Act and for Orders under Section 53 of the Energy Administration Act, effective August 1, 1984." January 1984. Revised, April 1984.

United States. Department of Energy. Energy Information Administration, DOE/EIA Quarterly Coal Report. 1983-III.

Watkins G. C. and Halpern, P. J. "Tax Normalization and the Cost of Equity Capital for Regulated Utilities." Discussion Paper 84. Calgary: University of Calgary, May 1984.

WestCoast Transmission Limited. Annual Report, 1983.

Wilson, Michael H. Economic and Fiscal Statement, presentation to the House of Commons, November 8, 1984.

Zuker, R. C. And Jenkins, Glenn P. Blue Gold: Hydro Electric Rent in Canada. Ottawa: The Economic Council of Canada, 1984.

April 1985

CANADIAN ENERGY RESEARCH INSTITUTE

PUBLICATIONS FROM JANUARY 1983 TO DATE
(A Complete List of CERI Publications
is Available Upon Request)

Studies

No. 17 Energy and Regional Investment in Canada. Gordon W. Douglas and Ellen F. Battle. March 1983 (Price $20.00, 114 pages) ISBN 0-920522-28-9.

No. 18 Household Energy Savings: Options for the Future. Brian D. Sumner and Barbara E. Green. March 1983 (Price $20.00, 194 pages) ISBN 0-920522-27-0.

No. 19 Modelling Exploration Success in Alberta Oil Plays. Kenneth D. Foat and Alan J. MacFadyen. September 1983 (Price $15.00, 181 pages) ISBN 0-920522-29-7.

No. 20 The Oil and Gas Investment Climate: Changes Over a Decade. DataMetrics Limited. June 1984 (Price $15.00, 76 pages) ISBN 0-920522-31-9.

Appendix Volume to Study No. 20. The Oil and Gas Investment Climate: Changes Over a Decade. DataMetrics Limited. June 1984 (Price $12.00, 141 pages).

No. 21 Canadian and U.S. Heavy Crude Oil Markets: A Review and Prospects. Volume I. Canadian Energy Research Institute. April 1985 (Price $25.00, 175 pages) ISBN 0-920522-36-X.

Appendix Volume to Study No. 21. Canadian and U.S. Heavy Crude Oil Markets: A Review and Prospects. Volume II. Canadian Energy Research Institute. April 1985 (Price $10.00, 133 pages).

No. 22 Natural Gas for Vehicles in Canada: A Study of Market Penetration Problems. Brian D. Sumner. April 1985 (Price $20.00, 99 pages) ISBN 0-920522-37-8.

Client Research Reports

83-1 Potential Benefits and Costs of Canadian Electricity Exports. Ellen F. Battle, Gordon S. Gislason, and Gordon W. Douglas. April 1983 (Price $25.00, 288 pages) ISBN 0-920522-26-2.

84-1 The Costs of Transportation Fuel from Methanol versus Oil Sands. Brian D. Sumner, Tricia Gibson, and Z. Charles Slagorsky. December 1984 (Price $20.00, 100 pages) ISBN 0-920522-34-3.

85-1 The Wolf Lake Project: An Example of Benefits to the Canadian Economy from Commercial Oil Sands Development. Louise Czaja, Michael Kirkegaard, Walter Haessel and Gordon Douglas. March 1985 (Price $10.00, 67 pages).

Working Papers

83-1 Development Options for Maritime Coal. John A. Dawson. January 1983 (Price $7.50, 42 pages).

83-2 Development Options for Alberta and Saskatchewan Coal. Tricia Gibson. March 1983 (Price $7.50, 44 pages).

83-3 Development Options for British Columbia Coal. Kristi E. Varangu. April 1983 (Price $7.50, 107 pages).

83-4 The Impacts of Crude Oil Supply Changes and Supply Allocation. Douglas J. Haughey and Donald A. Bruton. May 1983 (Price $7.50, 72 pages).

83-6 The Potential for Energy Substitution in Canada. Brian D. Sumner. September 1983 (Price $7.50, 124 pages).

84-1 A Review of Oil and Gas Drilling Activity Forecasting Techniques. G. E. Angevine, S. R. Cain, and Z. C. Slagorsky. March 1984 (Price $5.00, 20 pages).

84-2 An Assessment of Benefits and Costs of Using Methanol as a Motor Gasoline Extender in Southern Ontario. Walter Haessel and Tricia Gibson. September 1984 (Price $10.00, 62 pages).

84-3 The CERI Energy Pricing and Demand Models: A Description and Internal Evaluation. L. A. Coad. October 1984 (Price $10.00, 45 pages).

85-1 The Implications of Canadian Natural Gas Deregulation. Douglas J. Haughey and Robert T. Liddle. January 1985 (Price $10.00, 97 pages).

85-2 A Partial Regional Comparison of Taxes and Subsidies on Natural Gas, Electricity, and Oil Products in Canada. L. Coad and K. Desbarats. May 1985 (Price $10.00, 78 pages).

Discussion Papers

83-1 The Alberta New Oil Royalty Formula: 74-04-01 to 82-12-31. Alan R. Webster. March 1983 (Price $6.00, 56 pages).

Presentations by Staff (available upon request)

83-1 Household Energy Costs: Recent Developments and Options for the Future. G. E. Angevine. Notes for Remarks at the "New Neighbourhood Forum," sponsored by the Ontario Ministry of Housing and Municipal Affairs, Toronto, January 31, 1983.

83-2 Net Regional and National Benefits of Canadian Electricity Exports. Gordon S. Gislason, Ellen F. Battle, and Gordon W. Douglas. Paper presented to the Canadian Electrical Association Generation System Planning and Operation Subsection, Vancouver, March 21, 1983.

83-3 Economic and Financial Implications of Lower Oil Prices. Walter Haessel. Paper presented at a conference on The Impact of Lower Oil Prices, sponsored by Data Resources of Canada, Sheraton Centre, Toronto, April 14, 1983.

83-4 Energy Pricing in the World and Canada. James A. MacMillan. Paper presented to the Canadian Chapter of the International Association of Energy Economists, Toronto, May 20, 1983.

83-5 Canadian Energy Issues and Outlook. Douglas J. Haughey. Paper presented to the Institute of Internal Auditors, Calgary, October 18, 1983.

84-1 The CANREM Model: Model Structure, User Experience and Potential Applications. Gordon W. Douglas, Gordon S. Gislason, and Ellen F. Battle. Presentation to the Canadian Electrical Association Meetings, Edmonton, March 15, 1984.

84-2 Canadian Electricity Exports: The New Opportunities. Ellen F. Battle and Gordon W. Douglas. Presentation to the International Association of Energy Economists, San Francisco, November 6, 1984.

Proceedings

International Gas Markets Conference. Proceedings of a Conference held on September 26, 1983, Calgary, Alberta. Edited by Shane Streifel. (Price $45.00, 247 pages) ISBN 0-920522-33-5.

Annual Report

Board of Directors' Report for the Year Ended March 31, 1984. ISBN 0-920522-32-7.